Community Choice Aggregation
Draft Implementation Plan
Working Draft
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Prepared Jointly by
The San Francisco Public Utilities Commission
And
The San Francisco Department of the Environment

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1. THE COMMUNITY CHOICE OPPORTUNITY ARISES OUT OF THE CALIFORNIA ELECTRIC CRISIS.

The California legislature responded to the Electric Crisis of 2001-2002 - with its soaring prices, rolling black-outs, and public concerns about market manipulation - by passing a number of new electric industry initiatives. Amongst these legislative initiatives was Assembly Bill 117 sponsored by then Assembly member Migden and passed in September of 2002. This bill authorized communities to aggregate the electric purchasing power of its citizens and businesses so as to: "*reduce transaction costs, provide consumer protections, and leverage the negotiation of contracts*".

Community Choice Aggregation (CCA) offers cities and counties in California an option to purchase electric power on behalf of their citizens. Purchasing power from independent suppliers rather than the traditional utility like PG&E is increasingly common-place across the U.S. Competitive retail electric suppliers are serving customers using more energy than is represented by the sum of the wholesale energy markets in California, Texas, New York or New England, and Community Choice Aggregations are operating presently in Ohio[1] and Massachusetts[2]. In California today, universities, schools, businesses and cities aggregate their electricity purchases from Electric Service Providers (ESP) through Direct Access. The City's implementation of a CCA program will be part of the trend of seeking alternatives to utility provision of electric supply.

Mayor Newsom signed City and County of San Francisco (CCSF) Ordinance 0086-04 on May 27, 2004 establishing the direction for a CCA program in San Francisco and requiring the SFPUC and SFE to provide a Draft Implementation Plan for CCA. This CCA Ordinance called for a City CCA to help ensure the "*provision of clean, reasonably priced, and reliable electricity.*"

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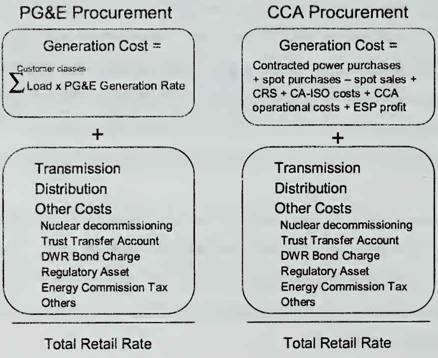
[1] The Northern Ohio Public Energy Council (NOPEC) is currently the largest example of municipal aggregation in the United States. NOPEC has recently announced a further three-year agreement with its wholesale supplier. Their website is: http://www.nopecinfo.org

[2] The Cape Light Compact has since 1998 provided electricity and energy efficiency services to participating residents and businesses in the Cape Cod and Martha's Vineyard area. Their website is: http://www.capelightcompact.org/

A CCA will serve its citizens with retail electricity supply contracted from a wholesale supplier. The CCSF CCA will deliver that electricity over Pacific Gas & Electric companies (PG&E) transmission and distribution lines, and bill its customers through PG&E's billing system. Therefore CCA is different from municipalization because PG&E retains ownership of and maintains responsibility for transmission, distribution and some customer service functions for CCA customers. PG&E will continue to read CCA customer meters and bill them for their use of PG&E's transmission and distribution system and well as non-bypassable charges such as those related to the energy crisis, PG&E's bankruptcy, public goods programs and nuclear power plant decommissioning.

This division of responsibilities between the CCA and PG&E is shown below.

Figure 1. CCA v. PG&E Comparison



1.1 CCA Offers the City an Opportunity for Local Control of Electric Resource Procurement and Setting of Electric Rates for Generation.

As a supplier of electricity to the residents and businesses of San Francisco, the City will take on a more prominent role in energy resource planning. CCSF will be able to both set the criteria for resource purchasing by the wholesale supplier and, within the constraints of offering competitive rate options, be able to set the framework for establishing electric generation rates for its citizens. A CCA can fulfill the goals of providing both clean and reasonably priced electricity – although these goals can be in short-term conflict with each other – and decision-makers will need to set near-term priorities. However a CCA can choose to provide far more than plain electricity supply and can offer other products and services to customers along with standard electricity supply, for example: competitive alternatives for existing Direct Access customers within the city, premium electricity supply products (e.g. 100% renewable or 10% solar electricity); energy efficient products and services and demand response programs; assistance with distributed generation including solar photovoltaic (PV) systems, and organization of continued opt-out processing for new customers.[3]

1.2 The Majority of San Francisco Businesses and Residents Can Become CCA Customers.

As required by AB 117 San Francisco citizens and businesses will have four chances to "opt-out" of CCA and remain a full PG&E customer, buying PG&E's power mix – customers not choosing to opt-out are automatically CCA customers. New customers opening an account after initial CCA implementation are anticipated to be automatically enrolled in the CCA program with a one-time opt-out opportunity after enrollment[4]. If a customer declines to opt-out but later wishes to return to PG&E service, it will face CPUC-imposed switching rules to return to PG&E service. These rules might include a minimum time on rates tied to wholesale electric spot prices and/or a minimum commitment to remain a PG&E customer.

[3] The turnover of residential and small customers within San Francisco is estimated at 25% per year. This degree of customer turnover is likely to require a highly organized approach to continued opt-out processing.

[4] Protocols for new accounts will be determined in Phase 2 of the CCA Proceeding.

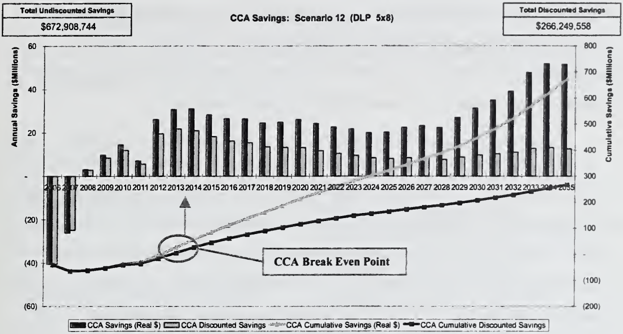
CCSF businesses and organizations that are not served by PG&E today will not become CCA customers unless they opt-in with CCSF's consent. This category of customers includes BART, and existing Direct Access (DA) customers. A key strategic decision for CCSF will be whether to attempt to recruit existing DA customers whose high electricity usage may help to lower power costs for all CCA customers.

1.3 Over the Long-Term CCA Can Provide Reasonably Priced Electricity to City Ratepayers

Under some scenarios evaluated in preparing this Draft Implementation Plan, CCSF has a reasonable prospect of offering customers a combination of of reasonably priced, cleaner energy, and lower fossil fuel rate risk to its citizens through CCA as called for by the CCA Ordinance – indeed the CCA best case offers the prospect of savings of close to $700 million over 30 years.[5] However in all cases – in the early years (2006-2008 or 2009) – it is reasonably likely that CCA customer bills would exceed those of equivalent PG&E service, e.g. in 2006 CCA customers could be charged about $84 million for the surcharge imposed by the State of California. This Cost Responsibility Surcharge (CRS)[6] set by the CPUC[7] is a charge that will be levied in addition to CCA generation and operational costs. Therefore despite an anticipated superior performance of a CCA wholesale supplier purchasing electricity, at lower cost than PG&E, it is the State imposed surcharge that will result in CCA customers having initially higher bills. During the period 2009-2010 it is anticipated that CCA customer bills will show small savings over PG&E equivalent bills and after 2010 CCA customer bills could be consistently lower due both to the performance of the City supplier and the Cities investment in a commercially available renewable power project – which at this juncture appears to be a wind project. The results of these forecasts are shown visually in Figure 2 below:

[5] However the potentially large CCA deficits in 2006-2008 means that on a net present value basis CCA does not turn positive until about 2013, and the total NPV of this scenario is about $266 million
[6] The Customer Responsibility Surcharge (CRS) is discussed below under Rate Setting Dynamics
[7] California Public Utilities Commission.

Figure 2. CCA Could Provide CCSF $266 Million in Net Benefits Over 30 Years



1.4 <u>A CCSF CCA Will Face Risks Which Can Be Overcome.</u>

To achieve the long-term goals set out by the Ordinance – clean, reasonably priced and reliable electricity - CCSF must successfully implement the CCA business with a supplier with consistently superior trading abilities, successfully invest with municipal financing in a large wind farm or other low cost commercially available renewable energy project, benefit from favorable wholesale electric market dynamics and have a favorable or at least neutral regulatory implementation of a range of electricity rules affecting both retail and wholesale markets.

Risks to the CCSF and its citizens associated with the outcomes above being less than favorable can potentially be mitigated.

One approach to mitigating near-term risk is to Phase-In CCA implementation over a period of, e.g. 6 months to 12 months. Benefits of Phase-In would include the opportunity to deal with initial customer transfer and billing problems as well as a gradual take-over of the electric supply function which should reduce risks related to

forecasting initial power requirements and allow a ramp-up of CCA portfolio responsibilities. However Phase-In could also result in considerable costs and complications. For example opt-out processing by zip code could encounter and probably multiply the complications surrounding customer turnover – which is considerable in San Francisco. A Phase-In approach is also likely to complicate and increase the costs related to Communications outreach programs.

Another risk reduction option would be for the CCA to also levy an exit-fee of some type on customers who leave the CCA for other electric service. For example in year 3 under one scenario a substantial CCA investment is made in a renewable energy project to serve a load forecast based on large customers remaining with the CCA. However, if in year 4 a sizeable number of the larger CCA customers attempt to depart the CCA for alternative electrical service (DA for instance) it may have an adverse impact on the economics of the renewable project. The CCA could develop an exit fee to apply to such customer departures and help ensure the economic viability of the renewable project.

Yet another approach to risk mitigation would be to postpone an immediate decision to proceed with CCA to await the outcome of a number of CPUC proceedings. The results of these proceedings – addressing such topics as PG&E's rate design for the period 2006-2009, the possible adoption of a CRS rate for the year 2007, the CCA Phase 2 proceeding dealing with CCA operational terms and conditions, Resource Adequacy Requirements applied to all LSEs' (Load Serving Entities) – should provide a firmer informational foundation for any BOS decision regarding CCA implementation. Given however the decision-making process and steps required to implement a CCA it may be true that a City CCA could not actually be implemented until 2007. The CRS charge in 2007 is also forecast to be lower which could result in a reduction in the short-term cost barrier facing CCA.

1.5 The Draft Implementation Plan Response to the Ordinance Requirements

The CCA Ordinance requires that the Draft Implementation Plan cover an itemized list of issues. Table 1 identifies those issues and where they are addressed within the Draft Implementation Plan.

Table 1. Ordinance Issues Mapped to Draft Implementation Plan Chapters

Ordinance Requirement	**Draft Implementation Plan**
Electricity Load Data	Customer Characteristics and Context – Chapter 2 and Appendix B.
Ratesetting Mechanisms and Costs	Ratesetting Dynamics – Chapter 3
RPS Compliance and Benefits of the Program	Resource Mix and Cost – Chapter 4
Use of Prop H Bonds	Muni Bond Financing – Chapter 5
Program Termination	Solicitation and Contracting Options Chapter 6
Contract and Bid Requirements	Solicitation and Contracting Options Chapter 6
Scope and Organizational Structure and Functional Responsibilities	Organizational Scenarios – Chapter 7
Information Dissemination	Communications Plan – Chapter 8
CPUC Proceeding Participation	CPUC Participation – Chapter 9

In addition Appendix A presents a fairly detailed first examination of the costs for CCSF to undertake a number of CCA functions with city employees, Appendix B provides details regarding the load forecast used by Altos Management Partners for the Chapter 4 scenarios, Appendix C provides examples of RFP's issued by some cities for

supplier services, and Appendix D provides a listing of current Electric Service Providers registered in PG&E's service territory.[8]

2. THE SAN FRANCISCO ELECTRIC MARKET WILL ATTRACT WHOLESALE SUPPLIERS.

Potential CCA customers in CCSF represent energy purchases larger than the single largest electricity customer in California: the UC/CSU system – a DA customer since 1998. A CCA in CCSF potentially represents about 5% of PG&E's energy sales and 7% of its customers. Given reasonable RFP requirements, it is highly likely that San Francisco as a single customer will be an attractive value proposition to wholesale electric suppliers. For example CCA revenues paid in rates by CCA customers could be $200 million annually, on par or greater than the City's current water and sewer revenues combined. Due to the electric market context and rules in California, the CCA is likely to engage in multi-year commitments to a supplier and potentially become an owner of new renewable power plants. CCSF could be a market leader in CCA, one of the early, if not the first of its kind in California,[9] operating in a still evolving energy market.

3. CPUC DECISION-MAKING WILL DETERMINE THE RULES FOR CCA IMPLEMENTATION AND OPERATION.

CCA development is tied to several sets of rules. Below Table 2 illustrates the CPUC CCA rulemaking calendar. A CCA can, in theory, file an Implementation Plan with the CPUC after February 2005 and assuming prompt action by the CPUC could therefore potentially begin operation in 2006.[10] However the CPUC final decision on Phase 2 of the CCA Proceeding will address a number of detailed operational aspects of CCA formation and operation. A CCA should await such a final CPUC decision or at least have a greater understanding of the likely framework of such a decision before filing an

[8] Appendix D is illustrative and does not indicate that CCSF would be limited to contracting with one of these suppliers.
[9] Other California cities/counties considering CCA implementation include Chula Vista, Santa Monica, the County of Los Angeles, Berkeley, Oakland and Pleasanton.
[10] January 7, 2005 Letter from Executive Director of CPUC to the Legislature Regarding CPUC compliance with AB 117.

Implementation Plan with the CPUC. Table 2 shows the existing CPUC proceedings that directly impact the CCSF decision to become a CCA.

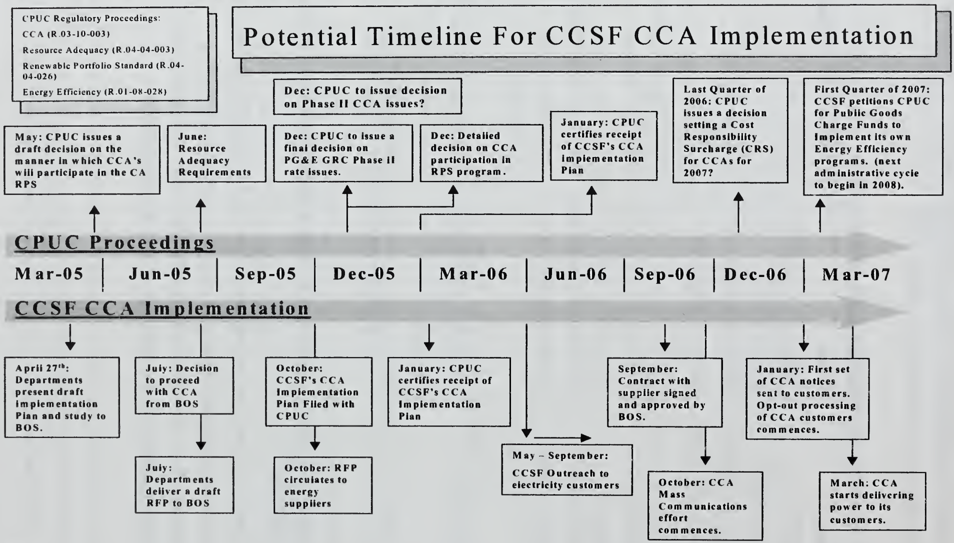
Table 2. CCA Rules Implementation Calendar At the CPUC

Proceeding	Status	Expected Final Decision
CCA Phase 2	Began January 25, 2005	By December 2005
CRS for year 2007	Begin in 2006?	?
PG&E Revenue Allocation and Rate Design for 2006-2009	PG&E filed update Feb 18, Parties filed testimony March 7.	By December 2005
Resource Adequacy Requirements	Implementation of Detailed Requirements for CCAs	June 30, 2005
Renewable Portfolio Standards Compliance	Implementation of Detailed Requirements for CCAs	Interim Decision Expected April 2005 and Final December 2005
Energy Efficiency	Availability of Public Good Charge Funds for CCAs	Decision 05-01-055 issued, Special status of CCA to be reconsidered by CPUC

4. POTENTIALLY A CCA COULD BE IMPLEMENTED IN THE CITY BY APRIL 2007

Chart 1 shows a potential CCA implementation timeline where the BOS makes a near-term decision to proceed with CCA and the milestones to be met based on the requirements of AB 117, the CCSF Ordinance, the CPUC Phase 1 CCA final decision, and other CPUC proceedings that directly relate to CCA implementation.

Chart 1: Potential CCA Implementation Timeline and Milestones[11]



[11] This timeline assumes that the CPUC does not require precise identification of the CCA wholesale electricity supplier at the time of filing a Draft Implementation Plan. This matter is being considered by the CPUC in Phase 2 of the CCA proceeding.

5. CCA CUSTOMERS WILL HAVE CHOICES – CCA SUCCESS DEPENDS UPON MARKETING A CREDIBLE PROGRAM.

CCA service will be considered a competitor to utility default service and DA service. Efforts to reopen the DA market have surfaced at the legislature in each of the last two years and it is possible that the DA market could reopen before CCSF launches CCA. To the extent that customers who improve CCSF's overall revenues and electric usage profile have a set of competitive options, the challenge and opportunity in designing products desirable to these customers increases.

To the extent that PG&E decides to offer a green pricing program to its customers, which many utilities do elsewhere in the US, CCSF will potentially have to compete against a "green" electricity product offered to its citizens by PG&E. Other products and services offered by the CCA may compete against other utility energy efficiency offerings, demand response programs, or competitive retailers offering distributed generation, energy management services or rooftop solar PV.

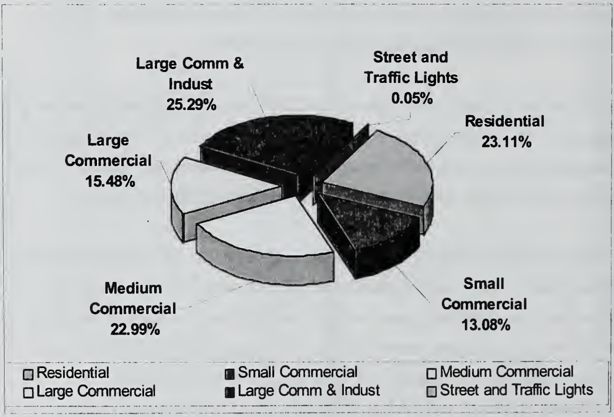
The opt-out structure of CCA means that CCSF's first goal is customer retention as opposed to customer recruitment, a far less expensive proposition. Given the competitive uncertainty regarding CCA implementation, customer communication requirements and outreach will need to be substantial prior to and during the initial opt-out process.

Moreover, CCSF will have to approach its product design – the set of products, their features, price, terms, packaging, distribution and promotion – as though it will have competition. Thus, the first question to be addressed is how to retain customers, and what do they need and want in order to remain CCA customers? The products and services offered will have to meet CCSF's unique market to be successful.

Although no market research has yet been conducted about customer response to potential products and services offering from a CCA in CCSF, basic customer demographics and energy usage patterns are available. Notably about 25% of larger business customer electric load in CCSF is currently served through DA - this equates to about 12% of the total potential CCA load. These accounts, some of the largest

electricity consumers in the city, will not be automatically enrolled in the CCA and will have to be recruited upon the expiration of their contracts if the CCA wishes to do so. This might be worthwhile since large business customers offer a significant revenue base and often have electricity usage profiles that are flatter than average.[12] Flatter profiles can potentially lead to lower costs to serve those customers and if their flatter profile helps to flatten out the average CCA profile, this may reduce electricity costs for all customers. **However it is the higher revenues available from CCA large business customers that are the most important consequence of their decisions to opt-out or choose CCA.** In addition maintaining a diversity of CCA customers will help reduce the regulatory risk of the CPUC advantaging any particular customer class in its PG&E rate design proceedings.

Chart 2. Estimated Generation Revenues By Customer Class



[12] Flatter usage profiles are defined as customer consumption that has relatively little fluctuation over a 24 hour, weekly, or seasonal basis. Usage load profiles are described in Appendix B.

Chart 2 above demonstrates the importance of large customers who comprise about 64% of the potential CCA revenues but only comprise a little over 1% of potential CCA accounts.

CCSF residential customers also consume a smaller proportion of electricity in the higher consumption tiers 3, 4, and 5 than the PG&E average. This is important since PG&E electric generation rates for these tiers are far higher than the Tier 1 and 2 rate levels. Opt-out of CCA residential customers who consistently take power in tiers 3, 4 and 5 could also adversely impact the overall economics of CCA.

It is important to recognize that the generation portion of electricity delivery costs varies significantly among customer classes and therefore the impact of higher than PG&E generation rates on customer's bills will also vary. For example for the average CCSF residential customer the generation portion of the electricity bill is about 35%, whereas for the largest commercial customers the generation portion of the bill is about 65%. Hence the city should anticipate that large commercial customers would pay particular attention to the rates offered by CCA.

More detailed information about CCSF's electricity usage and customer demographics can be found in Chapter 2: Customer Characteristics and Context.

6. HOW WILL THE CCA SET RATES IN A COMPETITIVE MARKET?

Ratesetting, customer mix and resource planning are intertwining issues. Change the composition of one of these categories and the other two will have to balance that change. Together they define the boundaries of product design. All three-product design factors are affected by the rules in which the CCA will operate as well as dynamics of the retail and wholesale markets surrounding the CCA.

Ratesetting goals are another key decision that must be made before moving forward with CCA. For example, requiring a supplier to provide power, at whatever level of greenness, in a manner that very closely matches PG&E's generation rates, for multiple years, for <u>all</u> customer classes may well result in increased costs for all customers in the

early years of CCA – with potentially significant opt-out of business customers. However rate-setting flexibility could allow for offering decreased or stable costs for large customers, which in turn reduces opt-out, and thereby results in improved CCA rates for all customers. The trade-offs between setting more stable rates for larger customers in the early years of CCA implementation and the consequences of this action on the rates for smaller customers is an important determination that needs to be made prior to CCA implementation.

Predicting PG&E's generation rates, the major competitor to CCA, is a complex forecasting exercise. PG&E no longer provides an open-book review of their resource mix and power contract terms – indeed due to concerns about use of market power and negative impacts on PG&E ratepayers a substantial amount of information regarding PG&E's contracts is now held confidential by the CPUC. This makes the forecasting of PG&E's average generation rates a complex process. Of course allocation of PG&E's generation costs among customer groups is also a dynamic process subject to CPUC regulation. PG&E's current rate allocation proposal in its General Rate Case (GRC) would, if approved by the CPUC, significantly lower generation rates for large and medium customers in CCSF while increasing generation rates for higher consumption residential customers. The net effect of PG&E's proposal would be to decrease the average PG&E generation cost for CCSF customers thereby increasing the competitive pressure on CCA generation rates. For purposes of the economic analysis conducted in Chapter 4 the assumption is that PG&E's generation rates will change in 2006 in the direction of reducing large and medium commercial customer bills.

PG&E is also embarking on contracting initiatives for thousands of megawatts (MW) of power.[13] These new contracts will impact that utility's costs and ultimately its rates. As a result, predicting the rate charged to each customer class years in the future is risky and asking the supplier to assume that risk will increase the cost of electricity supply. In addition, CCSF will never exactly mimic PG&E's customer mix and thus

[13] Depending upon the timing and prices for these PG&E contracts there could be additional CRS costs facing CCA customers in San Francisco.

even if total rates could be matched, rate allocation between customer classes will not be identical.

CCA Customer mix can impact ratesetting since there is uncertainty regarding opt-out levels. The more confidence that CCSF can offer its supplier about its actual electricity needs, the less risk the supplier and ultimately the CCA customers will bear. However a mismatch of expectations about electricity use with reality could cause CCSF to end up with power it cannot sell for the price it paid, or power it has to buy to meet demand at a price above its rates.

Resource planning constraints clearly affect rates. Although different market scenarios will drive different results on whether different percentages of renewable power are more or less expensive for CCA customers (such as if Liquid Natural Gas (LNG) is introduced to California), the more tightly constrained any specific resource goals are, the more expensive it will be to meet them. For example, limiting the wind resource regions that can compete for inclusion in CCSF's CCA resource portfolio will decrease supply and likely increase the price of the resources offered. Maintaining a broad set of options and establishing selection criteria that include resource-planning goals will clearly identify what the trade-offs are for resources from different regions.

Ultimately, the ratesetting goals established by the Board of Supervisors will determine what model is used for the supplier RFP. For example at one end of the spectrum, some large energy buyers provide their energy usage history by customer category in an electric supply RFP and ask for the best price for each category. The winning bid sets the rate for that category. On the other end of the spectrum, customers can identify an index on which to peg rates as well as the rate structure desired – for example a percentage discount off of each customer's PG&E rate schedule. To the extent that the constraints established by such an RFP approach create risk, the price of risk mitigation to meet proposed contract terms will be factored into RFP bid responses.

7. CCA PROVIDES AN OPPORTUNITY FOR BOTH CONTROL OVER GENERATION RESOURCE MIX AND LOWER GENERATION COSTS – BUT OPPORTUNITIES COME WITH RISKS

In developing this Draft Implementation Plan, extensive economic analysis of the interplay between customer composition and electric consumption, resource composition, and resource ownership options were performed. The range of outcomes from this analysis demonstrates that in the early years the CPUC-established customer Cost Responsibility Surcharge (CRS) is the major impact on the cost-effectiveness of the CCA program. Since it is likely the CPUC will continue to conservatively set the CRS at the high-end of potentially reasonable outcomes, this one key assumption, if accurate, will likely make CCA uneconomic or near uneconomic when measured over the short-term e.g. 2006-2008 and potentially until 2010.[14] However in the intermediate term forward – after 2010 it is clear that a well managed CCA portfolio that includes commercially competitive renewable power – like wind turbines –will provide an opportunity for both lower cost power than under PG&E's generation rates – as well as a cleaner mix of power resources.[15]

The other major findings of the economic analysis are as follows:

- the long-term economic value of the CCA will depend upon the superior contracting abilities of the supplier chosen by the CCA;
- the ability of the CCA to bond-finance wind resource development or similarly low-cost renewable energy projects is vital[16];
- and CCA construction of base-load natural gas facilities is likely to result in uneconomic results based on more competitive base-load alternatives.[17]

[14] The CPUC is supposed to account for a true up of actual CRS incurred in setting a subsequent years CRS. While CCSF believes this could reduce the out-year CRS values we expect the risk aversion of the CPUC in setting a CRS value to overwhelm this impact.
[15] This assumes that the city can count its wind generated electric production for RPS credit.
[16] In the wind example, it is important that the CCA contracts such that the wind power is "shaped" for intermediate and peak load needs.
[17] This analysis is limited to natural gas base-load facilities and is not an analysis of natural gas plants intended to provide peaking power.

Of particular interest are the results of wind power investment for CCSF. Such investment appears economic only if the City can, via contracting, "shape" the wind-power delivery to replace wholesale market purchases of peaking power. However this investment in wind power will likely have to be much larger in MW output than is consumed by the CCA during peaking periods. This is a result of the assumption that the CCA will have to "re-buy" the shaped wind power for peaking needs in traditional 6X16[18] blocks of purchased power – a considerable portion of which is surplus to the CCA needs and is sold on the spot market. This wind project scenario, which assumes a City growth rate in electricity consumption of 1.65% per year, promises the greatest economic benefits of any of the scenarios examined in Chapter 4.

Another scenario examined in Chapter 4 is zero electricity growth. Under this scenario is it assumed that a combination of aggressive energy conservation programs, demand response programs, and facilitation of distributed generation (e.g. solar photovoltaic projects on commercial buildings in San Francisco) reduces the electricity growth rate in the city to 0% by 2013 **and that this zero-growth in consumption or peak-demand holds until 2035.** This scenario exceeds the energy efficiency and distributed generation goals called for in the Ordinance. This zero electricity growth scenario in combination with the wind project scenario discussed above also promises positive economic results, but somewhat smaller than promised by the wind project alone. However one fundamental assumption underlying the zero electricity growth scenario is that the dollar investments required to achieve and maintain the zero electricity growth scenario occur **outside of CCA revenues and costs.** That is, the dollar investments are assumed to occur via CCA access to the public goods surcharge dollars (discussed in Chapter 9), via ordinances by the city aimed at improving energy efficiency, and via large scale state-wide solar initiatives currently proposed by Senate Bill 1. If a combination of the public goods surcharge dollars and legislative initiatives are insufficient to achieve the zero electricity growth scenario then CCA generation rates would have to be increased to attain this goal – resulting in a reduced level of direct CCA economic benefits. The CCA might be able to levy its own public goods charge (PGC)

[18] Wholesale electricity products are currently sold in "blocks" that are either 7X24 (meaning 7 days and 24 hours per day) or 6X16 (6 days and 16 hours per day). This is discussed in more detail in Chapter 4.

for such purposes, but again, this will have the same result of increasing the CCA customers' overall bills.

In response to the preliminary SFPUC/SFE presentation to the Local Area Formation Committee (LAFCO) on March 22, 2005 we asked our economic consultants to diversify the types and increase the quantity of renewable power included in yet another scenario. This scenario assumes that a substantial amount of baseload renewable power is purchased under contract as well as a significant amount of peak-load power. In both cases the current market price referents established by the CPUC were used to price this power.[19] The economic results of this scenario are negative. This due to contracting for peak renewable power – assumed to be solar – displacing competitively priced wind power; and contracting for baseload renewable power – likely to be biomass – displacing less expensive traditional market-based supply. These results are discussed further in Chapter 4.

In addition to uncertainty around competitive market factors, the other major ongoing uncertainty is regulatory risk. For example, the implementation details of several CPUC proceedings could significantly impact CCA prospects. The detailed protocols for Resource Adequacy Requirements (RAR), expected to be issued during 2005, will help shape the supply contracting options for any supplier and potentially result in cost impacts sufficient to change the economics of CCA. PG&E is likely to contract for electricity supply by developing a portfolio of resource types and contract lengths, as well as ownership structures. This PG&E risk diversification strategy will also set the competitive context for CCA product development and resource planning.[20]

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[19] Market Price Referents (MPRs) were developed by the CPUC to use as an estimate of the long-term market price of electricity for use in evaluating bid products received during Renewable Portfolio Standard program utility power solicitations. The MPR methodology was adopted in CPUC Decision 04-16-015 (available at: http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.pdf). The CPUC established MPRs for the utilities' 2004 RPS solicitations in a recent ruling: http://www.cpuc.ca.gov/word_pdf/RULINGS/43824.pdf .

[20] One potential result of CCSF becoming a CCA would be to cause PG&E to meet its RPS goal of meeting of 20% renewable power consumption by 2010. This would result not from PG&E renewable procurement but, rather, from reducing PG&E bundled customer load due to San Francisco CCA departure.

The CCSF Ordinance requires the examination of Proposition H Bonds as a vehicle to augment CCA by providing for financing of renewable energy and conservation projects. Prop H bonds could offer lower cost debt than would be available to a commercial power plant developer. This cost advantage may be magnified if wholesale natural gas prices remain high or go higher. As long as gas prices are high enough that electricity produced by gas-fired power plants is more expensive than electricity produced at wind plants, for example, wind plants will be able to sell their electricity at the marginal price of power – the gas-fired price. In those circumstances, cost-based wind power generated from municipally financed facilities may be attractive enough to outweigh the risks of long-term power plant ownership or leasing. The other attractive aspect of wind plant ownership, or long-term leasing, is the lack of fuel risk, both on price and physical delivery. Chapter 5 discusses bond financing in more detail. However, the important conclusion from this chapter is that any City agency issuing the bonds for CCA based renewable projects would require at minimum both a credit-rating and demonstration of a stable CCA customer base and rate-making mechanisms.

A further market uncertainty, not captured in the economic analysis of Chapter 4, is the risk of late payment or non-payment by customers of CCA generation charges. As shown in Chapter 2, late payment by CCA customers could amount to over $2 million a month. Currently PG&E does not levy late fees, hence a sharing of late fees between PG&E and a CCA is not an option. It is likely that a supplier would charge an incrementally higher price for wholesale supply to offset any continuing late payment circumstances. Of even more importance is that under existing CPUC rules non-payment of the CCA generation portion of the bill by a customer would not warrant disconnection of that customer's service by PG&E. In fact, under current rules it is conceivable that a customer could pay just that portion of their bill that is considered "disconnectible" – currently defined as a subset of PG&E's charges and not face service interruption. The CCA's only recourse in such a situation would be to return that customer to full PG&E "bundled" electrical service. CCSF is pursuing changes to this rule as a matter to be determined in CCA Phase 2 of the CPUC proceeding.

8. THE CCA RFP CONTRACTING PROCESS IS CRUCIAL TO CCA SUCCESS.

Ideal RFP development ideally requires BOS decisions on ratesetting goals, customer approach, resource planning, and product line before RFP issuance. The RFP sets the stage for the partioning of risk between the winning bidder and CCSF in the contract. One crucial factor in designing an RFP is to set the supplier incentives to fulfill the CCA goals (e.g. a shared savings/losses approach with a wholesale supplier might set the right incentives for aggressive supply contracting).

Another major decision required prior to establishing the RFP approach is to determine the level of services requested from a supplier. Will all retail functions be performed by the supplier, with only contract management and final rate setting performed by CCSF? Or, would CCSF prefer to adopt a business model that more closely matches the water and sewer service in San Francisco?

For example, CCSF through the Department of the Environment has been actively engaged in energy efficiency delivery to CCSF businesses. The CCA could take that activity a step further. A list of potential complementary products to electricity supply might include:

- Energy efficiency program development potentially via funds obtained from the PG&E PGC fund administration as well as from CCA revenues;
- Demand response programs and rates;
- Facilitation of distributed generation products, including solar PV.

Therefore the contemplated product line will be a key element of the platform from which the supplier RFP is developed. For example, a simple product line might suggest that the RFP be tailored to attract suppliers alone. In contrast, a more complex product line might require RFP development to contemplate teams of companies to serve the expected CCA needs.

A detailed discussion of RFP development for supplier services, including examples from other states and localities can be found in the Chapter 6: Solicitation and Contracting Options.

9. HOW WILL THE CITY ORGANIZE FOR CCA IMPLEMENTATION?

This plan proposes that a supplier perform a majority of the wholesale electricity business functions required to operate the CCA. For example, the supplier should assume responsibility for daily power operations: scheduling power and settlement with the California ISO. That responsibility will extend to resource procurement risk management and credit management with generators, though the level of that responsibility may be affected by decisions around municipal power plant ownership. The wholesale power responsibilities of the supplier should be guided by resource planning direction provided by the CCA both in the RFP and as necessary with additional interaction with the supplier.

City employees working for the CCA could perform a substantial range of customer service related functions, including customer care, communications, and product development, marketing, and energy efficiency and demand response. The CCA could also choose to have substantial involvement in bill verification and opt-out processing, or ask the supplier to take on that responsibility and leave the CCA with only auditing responsibilities. In all cases, the CCA will have to maintain a regulatory and legal function as well as a supplier contract management function. Ordinance 00-86-04 appears unclear on this point since on the one hand it proposes an RFP which contracts out most, if not all, of these customer service functions, while on the other hand requesting that the Draft Implementation Plan provide organizational options for the CCA.

The most costly undertaking for a CCSF CCA to handle "in-house" would likely be bill verification and accounts receivable since this would likely require a significant investment in a Customer Information System (CIS). However, it is the Sales,

Marketing, and Outreach component that is likely to require the largest staffing – since it is also this function which would undertake energy efficiency and demand response program responsibilities. It appears that specialized functions like scheduling and CAISO communications should remain with a supplier – at least at the beginning of the CCA program.

10. HOW TO COMMUNICATE THE CCA OPPORTUNITY?

CCA formation and implementation will require an extensive public communications effort. The communications plan will need to be constructed to address three distinct phases: planning, launch, and regular operation. The CCA will need to mesh regulatory and legislative requirements with customer retention and product marketing (i.e.energy efficiency, solar.) The communications planning process will need to begin concurrent with the discussion of the Draft Implementation Plan. Funding for communications prior to operations will also require a decision by the Board of Supervisors.

There are several reasons why San Francisco citizens are already well aware of energy issues, some of which are unique to California, others unique to San Francisco. The California Energy Crisis increased customers' awareness and attention to energy issues. The popular media coverage was intense and supplemented by utility messaging and state-sponsored outreach by programs such as "Flex Your Power." San Francisco customers are familiar with PG&E's bankruptcy, repeated repeated efforts to form a municipal utility, and the efforts to shut down Hunters Point and Potrero power plants.

On a more positive note, citizens have seen San Francisco pass ballot measures to fund renewable energy and energy efficiency projects and are likely familiar with the fact that solar projects have been completed in San Francisco. Many residents are familiar with the windmills at Altamont and the geothermal facilities at the Geysers. Some potential CCA customers chose green power for their home or business while they were permitted to do so through Direct Access.

All of that background serves as a backdrop to the development of communications messages and materials for CCA. The relatively high awareness about energy issues offers a context to work from, but also sets up potential questions and confusions that will have to be addressed.

Chapter 8 sets forth a very preliminary and bare bones budget and overall organizational strategy and approach for a CCA communications strategy. The Departments anticipate substantial change to this approach as a result of the requirements imposed by the CPUC in the Phase 2 proceeding as well as thorough review by the CCSF communications experts.

11. CONCLUSIONS - THE CCA OPPORTUNITY.

- **Under some scenarios**, a well-executed community choice aggregation can offer San Franciscans clean, reasonably priced and reliable electricity as well as other products and services. **Through 2008 and potentially longer**, customer bills under CCA are likely to be higher than bills would have been from PG&E due to the CPUC-mandated Cost Responsibility Surcharge. However, if the city decides to commit to a CCA for a substantial period, the economic impact to citizens could start to turn positive in 2009 it will then take a number of years before the deficits of 2006-2008 are erased.

- If the city were to set rates to follow costs, this analysis suggests that average residential customers would **pay about about $3.50 more/month in 2006 for power that starts on the path to match the renewable goals laid out in Ordinance 0086-04.**[21] The city must decide what its first priority will be for designing retail power products -- is it serving a certain segment of the city's citizens and businesses, a specific rate level target, or a renewables content hurdle? The customers served, the product price and composition are interconnected elements of product design. If you change one of these three key elements, the others are likely to be impacted as well.

[21] This bills increase assumes that residential customers and commercial customers would pay equal shares of the potential cost increase.

- Although the CRS results in a near-term higher cost service, in the longer-run, **a CCA can offer a higher renewable energy component to its citizens and businesses at potentially lower cost** than PG&E's default service. A CCA could finance new renewable facilities using lower cost municipal financing and possibly a higher debt to equity ratio. In a fluctuating gas price environment, a higher renewable energy option offers lower rate impact risk than gas plants would. However economic analysis of meeting this high renewable energy component with a variety of renewable energy sources, which is beyond the wind scenario discussed above, is on going.

The major areas of risk to a CCA setting up to do business now are as follows:

- Regulatory: Final state-mandated requirements for CCA operations and CCA resource adequacy and renewable portfolio standard (RPS) compliance are still under development.

- Strategic: The city will have to decide what customers to target as well as what rate and resource portfolio constraints it will adopt for product design.

- Volume: Customers will have the option to opt-out of CCA without penalty at the beginning of the program or upon setting up a new account. Large numbers of potential customers choosing to opt-out will impact product design and rate structure. The scenario where a large amount of commercial load opts out of the CCA has a significant impact on CCA costs such that the CCA for remaining customers never appears economic given existing CPUC rate design policy for small customers.

- Operational: Higher than expected losses of customers due to glitches in customer switching, or losses in revenues due to glitches in billing would destabilize an otherwise well-planned CCA business. Delinquent accounts could also adversely impact CCA economics since current CPUC rules do not permit PG&E to disconnect customers for non-payment of CCA charges.

- Market: The CCA success is also dependant on market conditions affecting its ability to obtain a strong credit rating, succeed with bond sales, or sustained high or volatile gas prices.

- Execution: Even if the CCA contracts for nearly all retail and wholesale CCA functions, it will have to successfully develop and execute an RFP and supply contract for its supplier and work with that organization to launch CCA in San Francisco.

- Default/Credit: The CCA will have to set up contingency plans to deal with a scenario of supplier failure or breach of contract.

Termination: Once launched, untimely termination of the CCA program could result in significant costs for CCSF and CCA customers. PG&E would need to plan for resumption of generation responsibilities for CCSF customers.

The city has a set of decisions it must face in order to proceed with CCA:

- Align CCA planning with the outcome of various CPUC proceedings, or proceed with development of an RFP and Implementation Plan filing with the CPUC.
-
- Rank its goals for customers served, rate levels and resource mix;

- Identify its preference for its customer service business model: city employees or contracted services;

- Identify public financing approach for CCSF investments in renewable generation;

- Determine its RFP approach;

- Chose a CCA start-up funding mechanism.

Community Choice Aggregation Draft Implementation Plan

Chapter 2: Customer Characteristics and Context

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Table of Contents

1. INTRODUCTION: CUSTOMER CHARACTERISTICS AND CONTEXT

The electric customer composition and consumption characteristics of customers within San Francisco lay the foundation for the viability of a CCSF CCA program. Usage patterns and product expectations can vary significantly by customer type influencing how the CCA designs and sets the rates for its energy commodity and energy services. In order to understand the CCA potential in San Francisco, it is essential that electric customer composition and energy usage patterns and characteristics be well understood within the context of electric generation rate design.

California law requires that CCAs provide universal service to all customers within the municipality's jurisdiction and provide an opportunity for such customers to opt-out of the program and continue service with the local Investor Owned Utility (IOU) if so desired. While the Phase 1 Decision of the CPUC left to CCA discretion the actual marketing of the CCA program it does require that CCAs clearly offer universal service to residential customers. The Departments believe it is the intent of any CCSF CCA to offer service to all customers who are available to take service. However, in San Francisco this does not mean that every electrical customer will necessarily be available to participate in the CCA. For example, CCSF municipal customers already being served by the Hetch Hetchy power system are presumed not to be available to participate in the CCA. Moreover, there are some electrical customers within CCSF that are under contract and still receiving power services from ESPs via the Direct Access (DA) market, which was suspended to new customers in 2002 by the State Legislature as a result of the energy crisis. As their contracts expire these DA customers may choose to participate in the CCA. Alternatively, they can continue to sign contracts and receive energy services from eligible ESPs in the California DA market.

Second, until the opt-out process is complete, CCSF cannot be absolutely certain of its final customer base, nor what the customer class composition of that base will be when it is required to deliver its first electron over PG&E's wires. What is certain is that the number, types, and usage characteristics of customers that participate in the CCA have direct feedback into the CCA's energy procurement strategy and costs as well as the potential rates the CCA can charge customers for power. Although it may be impossible to know definitively what the CCA customer base will be after opt-out, with load and customer data received so far from PG&E we do know what the market is for a CCSF CCA.

This chapter examines in detail the potential CCSF CCA customer base and its characteristics and context. Specifically, this chapter examines the following areas:

- The number and type of customers by customer class (residential, small commercial, medium commercial, etc.) as well as its consumption patterns.
- How the customers and load available to the CCA compare to PG&E's system average characteristics.

- CCSF's potential California Alternative Rates for Energy (CARE) customers – customers that receive a substantial discount on their energy bills based on economic eligibility.
- CCSF's Residential Class consumption patterns including baseline consumption data.
- Delinquent accounts and uncollectible funds data for CCSF. Data on CCSF accounts that are at least 60 days past due and eligible for service shut-off.
- The generation component of CCSF customers' bills that represents the CCA's potential energy procurement business opportunity.

The departments are acquiring electrical load data as directed by the Ordinance in a series of requests submitted to PG&E.[1] Prior to the CPUC's CCA Rulemaking Phase I Decision (D.04-12-046) issued on December 16, 2004, the IOUs only released data that was not protected under the CPUC's "15/15 Rule."[2] The "15/15 Rule" was established for direct access to protect customer confidentiality in data releases to electric service providers.[3]

D.04-12-046 supports the claims of prospective CCAs that municipalities should be provided the necessary customer data to make an informed analysis of the prospects of a CCA program. The decision concludes, "CCAs can be entrusted with confidential customer information," but established procedures to assure that "cities and counties do not seek information casually." To those ends the Commission ordered that as a "condition of receiving utility information the mayor or chief county administrator sign a letter attesting to the city or county's intent to "investigate" or "pursue" status as a CCA. (See attached letter).

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[1] The CCSF CCA Ordinance directed the Departments to acquire the following electrical load data from PG&E for purposes of this Draft Implementation Plan:

1. Energy consumption for each customer class for a given period of time;
2. Residential and nonresidential load shapes and most recent hourly load shapes;
3. Dynamic and static load profiles posted daily at PG&E's website by rate categories;
4. Number of current IOU customers;
5. Sum of customer non-coincident demand (kW or MW). (This data is used for calculating group diversity factors. The degree of diversity affects the utility's system requirements.);
6. Coincident peak demand (kW or MW) including the time of day and date (This data is used to determine the size of procurement contracts as well as revenue allocation and rate design.);
7. Electric load (kW or MW) for each hour of the year (8760 hourly loads) based on the most recent 12 months of load research. (This data provides information on the basic load shape for customer classes within a specific community or area of the community.);
8. Energy billing determinants (kWh) for each season and time of use period that applies to the tariff schedule (e.g. summer peak, summer partial peak, summer off-peak, winter peak, winter partial peak, winter off-peak, etc); and
9. Any other data the Departments deem necessary.

[2] As of the time of writing this draft, the IOUs were still developing data release procedures for potential CCAs pursuant to D.04-12-046.

[3] D.97-10-031 requires that any grouped data releases issued by utilities to electric service providers must contain at least 15 customers and no individual customer's information may be more than 15% of an assigned category (rate schedule for instance). The "15/15" Rule decision directed the utilities to protect data if the number of customers is below 15 or any individual customer's data exceeds 15% of the total by combining categories until the rule is no longer violated (blending data for two similar rate schedules for instance).

1.1 Customer Types and Electrical Load Characteristics

At CCSF's request PG&E provided the departments with 12-month energy consumption data and number of customers by rate class for the year 2003.[4] PG&E provided the data divided into approximately 20 customer rate schedules, which the departments aggregated into 6 larger customer classes as shown below:

- Residential: E1, EL1, E7, EL7, E8, EL8 and E9A
- Small Commercial: A1, A6, A15, AG5B
- Medium Commercial: A10
- Large Commercial: E19
- Large Commercial/Industrial: E20
- Street and Traffic Lights: LS1, LS2, LS3, OL1, and TC1

To develop a load forecast for the CCA's potential customer base in 2006, CCSF utilized PG&E's system average growth rate of 1.65% as reported in its Long Term Procurement filing (R. 04-03-004) before the CPUC. Assuming that the number of customers will not vary significantly for CCSF a 0.5% growth rate was applied to the account numbers for all customer classes except Street Lighting and Traffic Controls.

Table 1.1: CCSF 2006 CCA Snapshot

Sector	Accts	Avg Annual Energy (kWh)	Total Annual Energy (MWh)	Demand (kW)	Avg Demand (kW)
Residential	326,406	4,546	1,508,413	344,599	1.1
Small Commercial	28,356	18,854	543,438	124,384	4.4
Medium Commercial	3,525	211,121	756,558	164,652	46.7
Large Commercial	762	757,998	587,372	96,913	127.1
Large C/I	94	9,074,324	870,769	147,584	1,563.4
Street/Traffic Lights	329	5,322	1,780		
Non-Res Sub Total	33,067		2,759,916	533,532	
Totals	359,144		4,266,550	878,131	
Coincident Peak				808,410	

Charts 1 and 2 below show the 2003 energy consumption and customer accounts by customer class data. Although the Residential Class alone comprises nearly 91% of all the potential CCA accounts in the City, it represents only 35% of total electricity sales. By contrast, Medium Commercial, Large Commercial and Large Commercial/Industrial accounts combined represent about 1.0% of the CCA's accounts versus 52% of electricity sales.

[4] PG&E redacted many of the number of accounts (customers) fields due to a breech of the "15/15" Rule.

Chart 1.1b: 2003 Numbers of Accounts by Customer Class

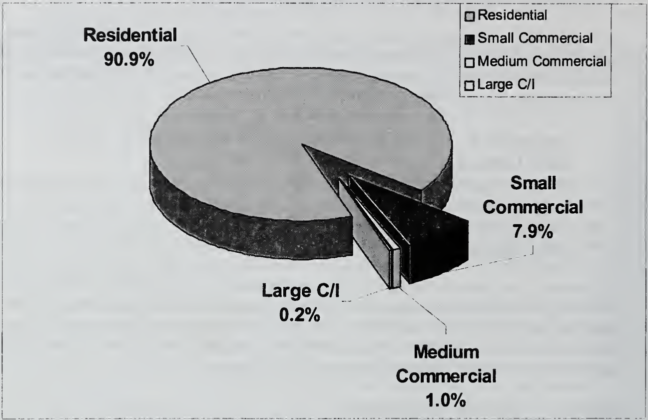


Chart 1.1a: 2003 Energy Consumption by Customer Class

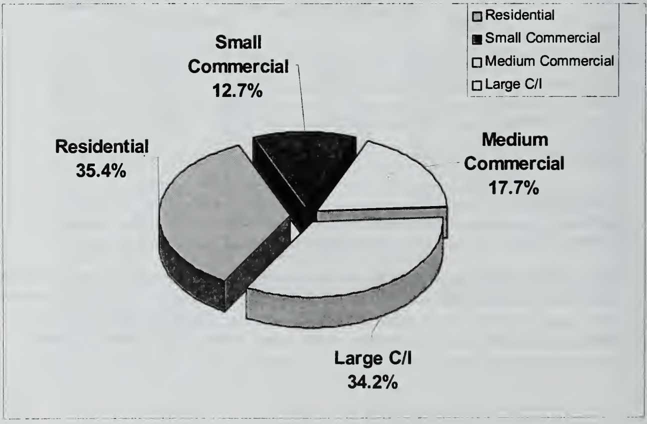


Chart 1.1c: CCSF Daily Max, Min, and Avg Energy Profile 2003

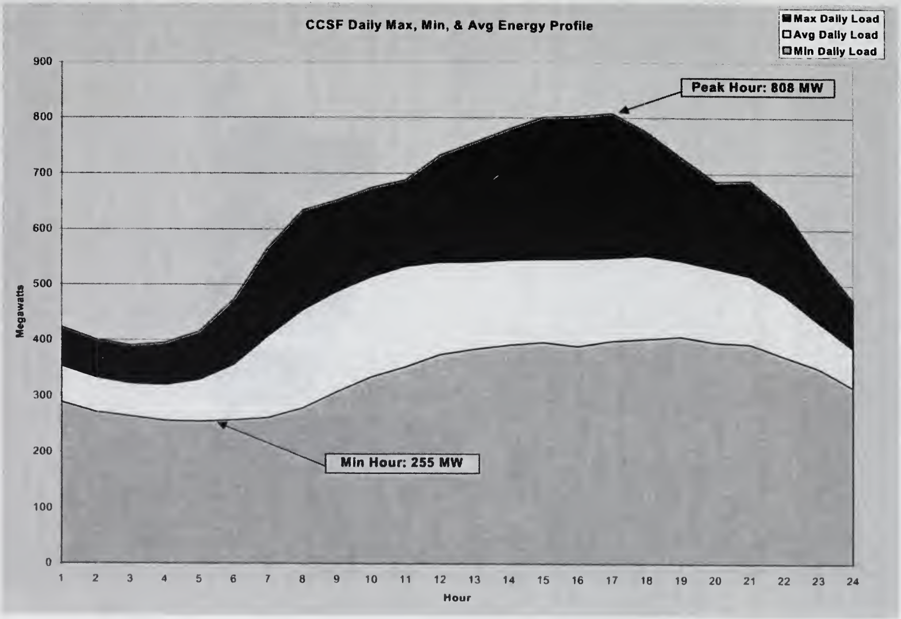
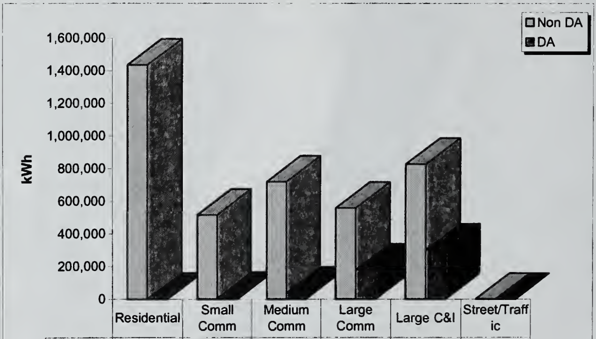


Chart 1.1c shows CCSF's maximum, minimum, and average hourly energy usage for 2003. CCSF used PG&E's system average load profiles also known as dynamic and static load profiles as posted on their website to shape monthly energy usage data provided by rate schedule.[5] The CCA's demand peaks at 808 MW in hour 17 (5 PM) and reaches its lowest point in hour 5 (5 AM). However, on average CCA's peak load is between 500-600 MW at 12 through 6 PM and its minimum load is just over 300 MW at 4 and 5 AM.

1.2 Direct Access Electric Consumption in CCSF

The California Legislature created the direct access (DA) market in 1995 via Assembly Bill 1890, also known as the retail "Electrical Restructuring Act." The DA market allowed customers of the regulated utilities to leave the utility system to purchase electricity from private energy service providers (ESPs). The California DA market was suspended to new participants during the energy crisis of 2000-2001 by the CPUC in D. 01-09-060. The suspension barred new customers from leaving PG&E but allowed customers that were being served by DA providers at the time of suspension to continue being served by their ESP. The graph below illustrates the remaining penetration of direct access DA in the San Francisco market by customer class electrical demand.

Chart 1.2a: Portion of CCSF Electrical Load Served by DA in 2003



	Residential	Small Comm	Medium Comm	Large Comm	Large C&I	Street/Traffic
Non DA	1,436,145	517,401	720,311	559,231	829,050	1,695
DA	2,174	7,328	39,037	180,448	303,536	33

[5] CCSF's use of load profiles in forecasting the CCA's load is discussed in greater depth in Appendix B: Load Forecasting Assumptions. PG&E's dynamic and static load profiles (system average load profiles) can be found at: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml

In 2003, the DA marked served approximately 12% of the electrical load in San Francisco. Notably, about 25% of the City's Large Commercial and Large Commercial and Industrial customers receive electric service through DA. These customers receive service from ESPs on a contractual basis. For this reason, customers participating in the DA market will not be automatically enrolled in the CCA during implementation. Instead, the CCA will need to determine if it wishes to pursue DA customers as their contracts expire. These customers will have to "opt-in" to the CCA program if they wish to participate.

The DA market presents another potential area of uncertainty going forward for CCA. Efforts to reopen DA have surfaced in each of the past two years. Moreover, Governor Schwarzenegger has expressed his support of the development of a "Core/Non-Core" DA market for electrical retail competition.[6] The reopening of the DA market creates uncertainty for CCA in two ways. First, the DA market could reopen before CCA implementation occurs in San Francisco creating electric service competitors in addition to PG&E. Second, in anticipation of the opening of DA at some point in the near term, many large commercial and large commercial and industrial customers may opt-out of CCA service. However, it is also conceivable that large customers would choose to participate in the CCA program regardless of the DA option. This will likely depend on the terms and conditions of CCA service for large customers as well as any potential switching rules the CCA establishes for large customers. Switching rules are discussed in more depth in Chapter 9.

2. COMPARISON OF POTENTIAL CCSF CCA CUSTOMER BASE TO PG&E SYSTEM AVERAGE

Since the City is assumed to offer CCA service to all eligible electrical customers within its jurisdiction it is important to assess the CCA from the perspective of zero opt-out, or 100% participation. Contrasting the characteristics of this customer base to PG&E's system average is also necessary because the CCA will be competing with PG&E for the customers within its jurisdiction. PG&E develops rates based on the characteristics and cost to serve their average customers within certain regulatory constraints. Those constraints include legislatively required discounts to low-income customers as well as rate caps for residential customers for consumption up to 130 % of baseline. These constraints limit PG&E's ability to charge rates that correlate with their cost to serve such customers. To the extent that the CCA competes with PG&E's rates for energy generation, the CCA ratemaking process will also be constrained by these regulatory requirements.

As a percentage of PG&E's system load and accounts, San Francisco represents roughly 5% of total energy load and 7% of total electrical customers. The table below compares CCSF's customer class characteristics for 2003 to PG&E's customer characteristics for the same year as reported in its Federal Energy Regulatory Commission (FERC) Filing (Form 1).[7] In order to establish a more apples to apples comparison of load between CCSF and PG&E, the

[6] Quick note about "core/non-core."
[7] PG&E's FERC Form 1 is available on their website at:
https://www.pge.com/regulation/FERC-Form1/form1-2003.pdf

departments selected only the customer account and load data for the rate schedules on which PG&E provides service to San Francisco customers. PG&E serves additional load to customers under rate schedules that do not exist in San Francisco. That data was not included in the chart below.

Table 2a: CCSF and PG&E System Average Load Characteristics[8]

CCSF CCA (2003 Data)					
Sector	MWh	% of CCSF Total	Accounts[9]	% of CCSF Total	Avg Energy (kWh)
Residential	1,436,144.88	35.3%	321,558	90.8%	4,466
Small Commercial	517,401	12.7%	27,935	7.9%	18,522
Medium Commercial	720,311	17.7%	3,473	1.0%	207,403
Large Commercial	559,231	13.8%	751	0.2%	744,648
Large C/I	829,050	20.4%	93	0.0%	8,914,515
Street/Traffic Lighting	1,695	0.0%	329	0.1%	5,152
Total	4,063,833	100.0%	354,139	100.0%	11,475

PG&E System Average (2003 FERC Form-1)					
Sector	MWh	% of PG&E Total	Accounts	% of PG&E Total	Avg Energy (kWh)
Residential	28,523,482	37.3%	4,282,914	89.3%	6,660
Small Commercial	10,748,068	14.1%	400,740	8.4%	26,821
Medium Commercial	12,128,831	15.9%	54,536	1.1%	222,400
Large Commercial	10,730,160	14.0%	10,460	0.2%	1,025,828
Large C/I	13,887,466	18.2%	1,125	0.0%	12,344,414
Street/Traffic Lighting	425,643	0.6%	46,305	1.0%	9,192
Total	76,443,650	100.0%	4,796,080	100.0%	15,939

As Table 2a demonstrates, despite having a greater percentage of residential accounts, CCSF's electricity demand is slightly less residential than PG&E's. Small commercial customers are a smaller portion of San Francisco's overall demand than they are in PG&E's service territory. However, medium commercial and large commercial and industrial customers represent a higher portion of San Francisco's total load than they do in PG&E's

[8] 2003 Load data provided by PG&E. Data is not weather normalized. CCSF CCA data does not include BART, MUNI, or existing DA load.

[9] Medium Commercial, Large Commercial, and Large C/I account data was provided incomplete by PG&E due to application of the "15-15" Rule. CCSF estimated the total number of accounts for rate classes that were not provided by using PG&E's FERC Form 1 "KWh of Sales Per Customer" for these rate classes and dividing that figure into annual KWh totals for the associate rate classes for CCSF. CCSF is awaiting an update from PG&E pursuant to CPUC Decision 04-12-046.

system. Most notably, however, CCSF customers use on average less energy per account than similar customers in PG&E's system. San Francisco's average annual energy consumption per account in 2003 was approximately 11,475 kWh, whereas PG&E's was 15,939 kWh, or 39% more per account. San Francisco's lower average energy use per customer than PG&E's system average can be attributed to the impact of direct access, less air conditioning load, and less heavy industrial load.

3. CCSF RESIDENTIAL BASELINE PERCENTAGES

PG&E charges residential customers different rates for electricity based on the volume of their consumption during a given billing period using a "baseline" rate system. Customer electrical consumption is tracked according to consumption "tiers," or levels of consumption within and above the baseline quantity. Generally speaking, the more electrical energy consumed over a billing period, the higher the rates charged on a per unit basis (kilowatt hour, or kWh). At CCSF's request PG&E provided residential energy consumption within the city for 12 months of 2003 broken into the 5 consumption rate "tiers."[10] Residential tiered data allows CCSF to better understand how much energy the average San Franciscan household consumes as well as the average rates paid for that energy. The tiered rate structure starts with a baseline amount that is determined by climate zone region and reflects the typical energy consumption requirements of those geographic regions.

Baseline[11]
Tier 2 – 101-130% of Baseline
Tier 3 – 131 – 200% of Baseline
Tier 4 – 201 – 300% of Baseline
Tier 5 – 301% of Baseline and above

The IOU's are currently prohibited by the State Legislature (AB1X, 2002 legislative session) from raising residential electricity rates for consumption up to 130% of baseline, or through tiers 1 and 2. This rate "cap" presents a challenge for CCA rate design and price competition with PG&E. As discussed in more detail in Chapter 3: Ratesetting Dynamics, the CCA will need to decide if it wants to maintain the AB1X price cap for residential electricity consumption below 130% of baseline. The extent to which the average CCSF residential customer has more electricity consumption below the AB1X price-cap than does the average PG&E residential customer potentially leaves less room for the CCA to recoup

[10] PG&E charged CCSF for this data on a time and materials basis.

[11] San Francisco is located in PG&E's climate zone T baseline region and has a designated baseline quantity of 8.5 kWh/account/day in the summer – May through October – and 10.2 kWh/account/day in the winter – November through April.11 To calculate the baseline over the course of a billing period, the daily baseline quantity is multiplied by the amount of days in the billing cycle. If there are 31 days in a summer billing cycle, the allowable baseline quantity for a San Franciscan household would then be 263.5 kWh. For the same amount of billable days during the winter the baseline amount would be 316.2 kWh. Consumption above and beyond this baseline amount falls into higher rate tiers and the customer is charged the associated tier's rate for that consumption.

generation costs from the residential customer class. The bar graph below illustrates CCSF's tiered residential energy consumption in contrast to PG&E's system residential consumption pattern. Tiers 1 and 2, which represent usage up to 130% of baseline, are grouped together as are Tiers 3, 4, and 5 in order to graphically demonstrate what portions of the generation bill are subject to the AB1X cap and which are not.

Chart 3a: Comparison of the CCSF's Actual Residential Rate Tier Consumption to PG&E's System Average Applied to CCSF Residential Consumption[12]

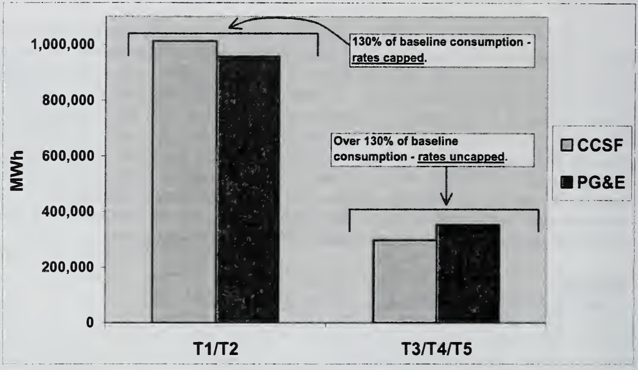


Chart 3a shows that in 2003 CCSF residential customers consumed more energy below 130% of baseline than did PG&E's system average. As a percentage of total residential electric energy sales, consumption in tiers 1 and 2 represented 77% of San Francisco's residential demand. By contrast, these same sales represented 73% of residential consumption in PG&E's system as a whole. This means that for San Francisco residential customers, PG&E can only raise its rate for 23% of consumption per 2003 statistics.

If the CCA uses PG&E rates as a ceiling for purposes of setting its own rates, the AB1X cap on residential electricity usage up to 130% of baseline becomes a defacto cap for the CCA whether or not the cap is formally adopted by the City. PG&E partially uses uncapped rates in tiers 3, 4, and 5, to make up for revenue shortfalls created by not being able to raise rates in the lower tiers. To the extent that the CCA's baseline consumption is higher than PG&E's and its uncapped consumption is lower, the CCA is forced to compete against a

[12] Tiered residential energy consumption data for CCSF was provided by PG&E for 2003. CCSF obtained PG&E's residential baseline percentages from the CPUC Office of Ratepayer Advocates (ORA). For comparative purposes, CCSF imposed those percentages on top of its own total residential energy demand totals (kWh) for 2003.

lower average generation rate for residential usage. The average generation rate for residential usage refers to what PG&E customers in San Francisco would pay if they stayed with the utility.

Because PG&E's residential rates are tiered based on total consumption over the course of a billing period, the average volume of energy consumed in San Francisco impacts what the average rate a San Franciscan residential customer pays. Customers who consume more power above 130% of baseline pay a higher average rate and raise the overall average "rate to beat" in San Francisco. Moreover, in terms of cost allocation, the high use customers help keep rates low for those who consume most of their power within or around the baseline level.

4. CALIFORNIA ALTERNATIVE RATES FOR ENERGY (CARE)

The California Alternative Rates for Energy or "CARE" program is a low-income ratepayer assistance program PG&E is required to provide pursuant to CPUC Decisions 89-07-062, 89-09-044, and 94-12-049. The purpose of the CARE program is to provide qualifying low-income residential customers of the regulated utilities reduced charges for energy. At the time of writing, PG&E residential CARE customers receive a 20% discount on their electric rates plus an exemption from the electric energy procurement surcharge.[13] The types of PG&E customers that qualify include all individually metered and certain sub-metered residential customers, non-profit group-living facilities, and qualifying agricultural employee housing facilities. CCSF is unaware of any of the latter type of CARE customers in San Francisco.

PG&E provided CCSF with data on participation in the CARE program in San Francisco for 2003 including the estimated number of CARE eligible customers, the number of enrolled CARE customers by rate schedule, and tiered energy usage by rate schedule. CCSF CARE data is shown contrasted with Non-CARE residential data in Table 4.1 below.

Table 4a: 2003 San Francisco Residential CARE and Non-CARE Data

2003	# of Accounts	%	kWh Demand	%	Est. Revenues ($)	%
CARE	39,371	12.24%	159,754,814	11.12%	$4,259,624.74	7.44%
Non-CARE	282,187	87.76%	1,276,390,066	88.88%	$52,972,631.54	92.56%
Totals	321,558	100%	1,436,144,880	100%	57,232,256	100%

To summarize, 12% of San Franciscan residential accounts participated in the CARE program, used 11% of total residential demand, and contributed 7.4% of total residential generation revenues in 2003. CCSF requested an update to PG&E's CARE data as well as information regarding estimates of "eligible" CARE customers in San Francisco. According

[13] The exemption from the surcharge which was enacted during the electricity crisis effectively increases the CARE discount above 20%.

to PG&E, in December 2002 there were an estimated 69,826 eligible residential CARE customers in San Francisco. At that same time there were only 38,637 customers enrolled, a 55% penetration rate. By July of 2004, the number of estimated CARE eligible customers in San Francisco dropped to 66,222 while participation increased to 82% or 54,571 customers. Whereas in 2003 CARE constituted approximately 12% of San Francisco's residential PG&E accounts, by the middle of 2004 that number had increased to roughly 17%.[14]

For comparative purposes, at the beginning of 2005, 21% of PG&E's residential customers (including San Francisco) participate in the CARE program. PG&E has a service territory CARE penetration rate of approximately 70% (903,619 participating customers to 1,283,879 estimated eligible customers). With 100% penetration, CARE customers would constitute 30% of PG&E's residential customers and 20% of San Francisco's. Therefore, in contrast to PG&E system average, San Francisco has a relatively low portion of customers either eligible for or participating in the CARE program. However, CARE still represents a significant social policy and ratemaking challenge for a potential CCA in CCSF.

The issue of how to treat CARE customers within the context of CCA is an important issue. There is indication that CARE customers for CCA will be treated similarly to CARE customers that participated in Direct Access. Under Direct Access, energy providers sold their electrical commodity to residential CARE participants at the same rate as they would non-CARE customers. The distribution utility (PG&E) applied the equivalent discount to their portion of the bill. The CPUC identified CARE discounts for CCA customers as an issue that will be addressed in Phase II of the CCA rulemaking proceeding (R.03-10-003).

5. DELINQUENT ACCOUNTS DATA

At CCSF's request, PG&E provided data on delinquent and past-due electric energy accounts for customers that receive service in San Francisco. PG&E tracks this data monthly for accounts that are at least $50 and 60 days past due and eligible for service shut-off pursuant to CPUC Electric Rules 8 and 11.[15] According to PG&E, delinquent balances on electric energy accounts in San Francisco represent 13% of total delinquencies in the utility's system. This figure is disproportionately high compared to San Francisco's contribution to PG&E's system total number of accounts (approximately 7%) and total electrical energy demand (approximately 5%). PG&E provided CCSF delinquent accounts data that included number of accounts by residential and commercial/industrial customer classes, total number of dollars past-due by the two rate classes by month, and the total amount of past-due dollars that are written off on a monthly basis. This data was provided for a one-year period beginning in September of 2003 and ending in September of 2004. Table 5a summarizes the data below.

[14] CCSF estimated this percentage by taking the number of CARE accounts in 2004 as compared to the total number of residential accounts in 2003. For this purpose CCSF made the simplifying assumption that the total number of residential accounts in San Francisco did not grow substantially over that timeframe.

[15] Electric Rules 8 and 11 are available at PG&E's website: http://www.pge.com/tariffs/ER.SHTML#ER

Table 5a: Delinquent Balances and Electric Write-Offs in San Francisco 09-2003 to 08-2004[16]

Customer Class Group	Avg Estimated Monthly Electric Generation Revenues (2003)	Sum of $50 Balances 60 Days Overdue (Gen Portion) - Monthly	Overdue Balances as a % of Gen Revenues	Estimated Monthly Electric Generation Write-Offs	Write-Off as a % of Est. 2003 Generation Revenues
Commercial / Industrial	$15,860,064	$1,605,809	10.12%	$37,673	0.24%
Residential	$4,769,355	$822,157	17.24%	$16,706	0.35%

According to the Table 5a, the generation portion of electric account balance delinquencies on an annual basis represent 10% of commercial/industrial revenues and 17% of residential revenues. Although these are high percentages of annual revenues for each of these customer groups, PG&E reports that it only writes-off about 0.25-0.35% of annual generation revenues as permanently uncollectible. This indicates that there are a good number of customers that "float" their balances over a couple months but tend to pay their bills eventually.

Table 5b: Delinquent Accounts and Average Overdue Balances Per Account in San Francisco 09-2003 to 08-2004

Customer Class Group	Total # of Accounts	Avg # of Delinquent Accounts/Month	Delinquent Accounts as % of SF Total	Total $/Account per Month	Generation $/Account per Month
Commercial / Industrial	32,252	292	0.905%	$5,499.35	$3,099.25
Residential	321,558	1938	0.603%	$424.23	$144.16

Table 5b shows the average number of accounts in San Francisco that had overdue electric bill balances of at least $50 for at least 60 days. Delinquent accounts as a percentage of total accounts by the residential and commercial and industrial customer class groups is minimal. According to the data provided by PG&E, these delinquent accounts represent less than 1%

[16] Since PG&E does not track electric account delinquencies by billing components (generation, transmission, and distribution), CCSF had to estimate the portion of electric account balances over $50 and 60 days past due attributable to generation. CCSF did this by first estimating what portion the generation commodity constitutes on the average electric bills for both the Residential and Commercial/Industrial customer groups in San Francisco. Total bill and generation revenues for these classes were determined using rate schedule level kWh and energy demand data and PG&E's total and generation only rates (demand charges were also calculated for medium commercial, large commercial, and large commercial/industrial customers and converted into a $/kWh adder). The total delinquent balances by customer group for the 12-month period from September 2003 to August 2004 was multiplied by the percentage of generation as a bill component for the residential (34%) and Commercial/Industrial (56%) customer groups. The same process was performed for calculating the generation portion of electric write-offs for the same 12-month period in San Francisco.

of the total accounts in each customer class grouping. The table also disaggregates the total monthly balance of overdue accounts into an average account delinquency both by total electric bill and by generation component only. This statistic shows that on a monthly basis the average delinquent residential account was an estimated $144.16 overdue for the generation portion of the bill only. Considering the average residential generation bill in San Francisco is about $14.25 per month this is a surprisingly high figure. The average delinquent commercial/industrial account is overdue $3,099.25 for the generation portion monthly. Although this is a much higher figure than is average for residential customers, it is also more in line with what the average customers in this customer class grouping pay on a monthly basis.

Delinquent account and balance information is important to CCSF in assessing CCA for several reasons. First, the CCSF CCA is required by law to *offer* service to all customers in San Francisco, regardless of whether or not they are currently paying their PG&E bills. Second, under the interim CCA service tariff proposed by PG&E, which mirrors "Rule 22" established for Direct Access service, the utility will not disconnect a customer's service for non-payment of CCA charges. Only non-payment of PG&E charges warrants service disconnection. Moreover, partial payments received by the utility *on delinquent accounts* are applied to the utility's disconnectable charges first. Under these rules a customer could pay only the PG&E (transmission and distribution) portion of the bill and not be discontinued from electrical service. The CCA's only recourse in event of customer non-payment of CCA charges is to return that customer to full or "bundled" PG&E service. A better option to equitably handle delinquent or partial payments may include making failure to pay any charges on the bill, after a certain period, "disconnectable," and applying any partial payments to amounts owed on a pro-rata basis. CCSF will seek to modify these rules in phase II of the current CCA rulemaking proceeding.

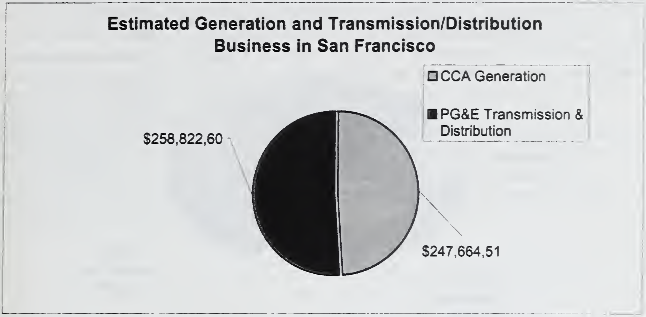
6. GENERATION AS A BILL COMPONENT

As previously discussed, CCAs provide commodity electrical supply and demand services to their participating customers. Electrons procured on behalf of customers by the CCA are delivered by PG&E on their transmission and distribution system. PG&E continues to charge for electrical delivery services and maintains meter reading and billing functions. This contrasts with full municipalization where the City and County would acquire the local utility's electrical delivery infrastructure and assume the full gamut of the electricity business in San Francisco including generation procurement, transmission and distribution services, and meter reading, and billing services.

In order to understand the portion of PG&E's electrical business that CCSF would assume as a CCA it is important to understand the size of PG&E's electrical energy business in San Francisco in general. Using San Francisco customer characteristics and energy demand as described above as well as PG&E's fully bundled electric rates and demand charges (for medium and large commercial and industrial customers) the SF PUC estimates PG&E's annual electrical energy revenues to be approximately $506,500,000.00 per year. Using a similar approach but only for generation related charges, the SF PUC estimates the potential

CCA portion of PG&E's San Francisco business to be around $247,000,000.00 per year, or 49% of total annual San Francisco electrical revenues.[17]

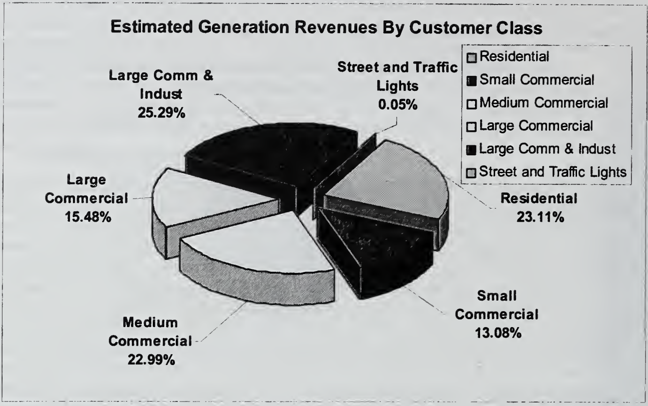
Chart 6a: Potential San Francisco CCA Generation Business



Generation revenues in San Francisco can be broken into customer class as shown below in Chart 6b.

[17] This estimate does not include revenues PG&E earns from DA customers.

Chart 6b: Estimated Projection of CCA Generation Revenue Proportions by Customer Class[18]



This chart reveals that commercial and industrial customers in San Francisco purchase 77% of all energy sold in the City by PG&E. Residential sales represent the remaining 23% of annual generation revenues. Generation as a portion of electric bills varies between customer classes as well.

Table 6a: Estimated Average Electrical Bills and Generation Component for Selected Rate Schedules

Rate Schedule	Description	Est. Avg. Monthly Bill	Est. Avg. Gen. Portion of Monthly Bill	Gen. as a % of Est. Avg. Mo. Bill
E1	Residential	$43.67	$14.25	32.63%
EL-1	Res CARE	$26.27	$8.79	33.46%
A1	Small Comm.	$208.27	$85.76	41.17%
A10	Med Comm.	$2,316.21	$1,366.16	58.98%
E19	Lrg Comm.	$7,406.89	$4,254.93	57.45%
E20	Lrg C&I	$88,327.28	$56,127.89	63.55%

Table 6a shows the generation component as a proportion of average total monthly electricity bills by selected rate schedules for each major customer class. As an overall portion of the

[18] To estimate generation revenues by customer class the SF PUC used 2003 data and PG&E's generation rates as of 01-2005.

electric business in San Francisco generation represents approximately 50% of total electric revenues. However, generation as a portion of customers' bills varies significantly across customer classes. For instance, the electricity commodity represents about one-third of the average residential customer's bill, but represents between 59% and 64% of what medium and large commercial and large commercial/industrial customers' pay. Table 6a also shows the impact of the CARE discount on residential bills and generation costs per account. In summary, customer load mix will impact the CCA's rates. At this time, PG&E's rates reflect that a higher percentage of commercial customers will push the average generation rate that we need to meet or beat up. This trend could change, however, depending on how PG&E's rates change going forward. In Phase II of their current General Rate Case (GRC, Application 04-06-024), PG&E is arguing to shift revenue allocation from commercial and industrial customers to residential customers to reflect the cost to serve those customers. Due to both their high consumption per customer and their generally higher rates, a high percentage of commercial and industrial customer participation will improve the general outlook for CCA in San Francisco.

Community Choice Aggregation Draft Implementation Plan

Chapter 3: Ratesetting Dynamics

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Table of Contents

1. RATESETTING POLICIES ARE CRUCIAL TO CCA SUCCESS

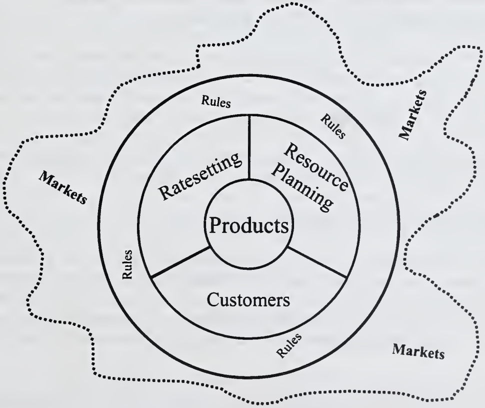
A critical factor for success of CCA in CCSF will be ratesetting. The number of customers opting-out of CCA service, the adoption of complimentary products and services, and the level of risk assumed by the customers and CCSF will all be strongly influenced by basic electric service ratesetting.

Ratesetting requires a decision-making body to decide:

- Which customers to focus upon;
- What constraints to apply to the electric service product or products offered;
- How to implement plans that will affect customer demand, including energy efficiency, load management, distributed generation and demand response;
- The competitive context of CCA rates relative to PG&E's rates and direct access rates;
- The ratesetting process, including frequency and triggers for rate review to assure that over a reasonable period, revenues cover costs.

Ratesetting, customer mix and resource planning are intertwining issues. Change the composition of one of these categories and the other two will have to balance that change. Together they define the boundaries of product design. All three-product design factors are affected by the rules in which the CCA will operate as well as dynamics of the retail and wholesale markets surrounding the CCA. Figure 1 illustrates these interconnections.

Figure 1 Ratesetting, Customer Mix and Resource Planning Impact Product Design



2. CCA RATESETTING POLICIES HAVE TO RESULT IN COMPETITIVE OUTCOMES

Customer mix can impact ratesetting since there is uncertainty regarding opt-out levels. The more confidence that CCSF can offer its supplier about its actual electricity needs, the less risk the supplier and ultimately, the CCA customers will bear. However a mismatch of expectations about electricity use with reality could cause CCSF to end up with power it cannot sell for the price it paid, or additional power it has to buy to meet demand at a price above its contract.

Before considering rate design, CCSF must explicitly determine its service strategy: which customers will it aim to serve? The CPUC has found that any CCA must offer service to all residential customers within its boundaries and can offer service to other customer classes.[1] For CCSF however, service to just residential customers alone would result in a relatively small CCA serving a customer segment with a relatively costly load profile and an existing PG&E rate design that is currently subsidized by other customer classes. This is an economically unattractive CCA option. A CCSF CCA should offer universal service. However, since AB 117 allows customers to opt out of CCA service, CCSF will have to consider how competitive it wants to be with the alternatives available to its potential customers. If CCSF sets service for all of its customers as a top priority, that decision will impact resource planning and ratesetting in order to make basic electric service as attractive as possible to each customer category. In particular, if maximizing customer retention is the first priority, CCSF must consider the impacts and risks of meeting or beating PG&E prices for current bundled customers, as some subset of CCSF's potential customer base will be very price sensitive.

Alternatively, CCSF could decide to maximize sales of renewable energy, which might be achieved by aiming at a subset of customers, or to minimize risk, which might effectively limit customers served. For example the CCA could create business rates that reward such customers making long-term commitments to receive CCA service.

Detailed information about CCSF's electricity usage and customer demographics can be found in the Chapter 2: Customer Characteristics and Context.

2.1 <u>PG&E Default Service is the Major Competitor</u>

All of CCSF's potential customers who do not currently take DA service will have the option of retaining bundled service from PG&E through the "opt-out" provision of AB 117. In other words, they will become CCSF CCA customers unless they exercise their right to choose to stay with PG&E. What PG&E offers to customers is "default service" which bundles supply of electricity with its delivery. Customers under CCA or DA

[1] Decision 04-12-046 of the CPUC, Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters, p.55.

service receive supply services from their CCA or supplier, and delivery services from PG&E.

However, default service may not be the only option for customers from PG&E in the future. If PG&E decides to offer a green pricing program to its customers, which many utilities do elsewhere in the US but PG&E currently does not, CCSF will have to compete against a "greener" electricity product offered to its citizens. Other products and services offered by the CCA may compete against other utility energy efficiency offerings, demand response programs, or competitive retailers offering distributed generation, energy management services or rooftop solar Photo Voltaic (PV) systems.

CCSF will have to approach its product design – the set of products, their features, price, terms, packaging, distribution and promotion – as though it will have competition. Thus, the first question to be addressed is how to retain customers, what do they need and want in order to remain CCA customers. CCSF is a tight, diverse, unique market with customer segments that are different than Ohio or Texas. The products and services offered will have to meet CCSF's unique market to be successful.

2.2 Direct Access is also a Current and Future Competitor

About 25% of larger customer business load in CCSF is served through DA. These accounts, some of the largest electricity consumers in the city, will not be automatically enrolled in the CCA. CCSF will have to decide whether to recruit these customers in anticipation of the expiration of their DA contracts. Individual customer analysis will have to be performed to assess how either these customers' electric use (load) profiles, or revenues from these customers could improve the economics of CCA for all customers. Flatter load profiles potentially can lead to lower costs if adding these customers to CCA flattens out the average CCA profile. To the extent that customers who improve CCSF's overall load profile have a set of competitive options, the challenge of designing products and rates structures desirable to these customers increases.

Although legislative activity to reopen DA to new customers has occurred in both of the last two years, today DA remains suspended for new customers. Current DA customers may continue on that service, but customers who did not have DA contracts by 9/20/2001 may not choose DA service at this time.[2] Current DA customers returning to bundled PG&E service must provide six months of advance notice and, once returned, must take utility service for at least three years. Thus, in order to prevent a customer who might be attractive for CCSF from choosing utility service upon their DA contract expiration, a CCA marketing team would have to identify attractive customers and recruit them to CCA service in advance of the expiration of their DA contract.

The factors to consider in evaluating the value of recruiting DA customers will be:

- The value of customer base stability for planning purposes;

[2] Customers with multiple facilities, for example a retail chain store, do have the ability to add facilities to their DA contract if other facilities leave the contract. This might occur when one facility is closed and is replaced under their DA contract by a new store located in another city. So, some business facilities in San Francisco could end up under DA contract even if DA remains suspended as it is today.

- The desired customer mix and overall load;
- The impact on rate design for other customer categories;
- The preferences of these customers for product design and how that impacts resource planning;
- The frequency or triggers to add customers to its CCA service, given the cost and revenue risks.

If CCSF wants to serve current DA customers, it will have to design products valuable to these customers. Prices that offer either lower costs than PG&E or fixed rates are offered to DA customers today. Thus, in order to recruit these customers, CCSF would have to offer products that matched or improved upon these features. Further complicating the current DA customer decision will be its ongoing responsibility to pay off any remaining DA CRS undercollection at 2.7 cent/kilowatt-hour (kWh) CRS, and then pay the CCA 2 cent/kWh CCA CRS going forward.[3]

3. CCA RESOURCE PLANNING RESULTS IN CCA RATES

3.1 Resource preferences will set the CCA rates

Resource planning directly impacts rates. Although different natural gas price market scenarios will drive whether a greater proportion of renewables in CCSF's portfolio is more or less expensive for CCA customers, the more tightly constrained any specific resource goals are, the more expensive it will be to meet them. For example, limiting the wind resources regions that can compete for inclusion in CCSF's CCA resource portfolio will decrease supply and likely increase the price of the resources offered.[4] Maintaining a broad set of options and establishing selection criteria that include resource-planning goals will clearly identify what the trade-offs are for resources from different regions.

3.2 Some Resource planning rules are Outside the CCA Control

The CCSF CCA Ordinance contemplates a higher renewables supply commitment compared to California's existing RPS (Renewable Portfolio Standard) requirement for IOUs. The rules dictating how ESPs and CCAs will be treated in relationship to the IOU RPS standards are under development.

CCSF will also have to meet the CPUC's Resource Adequacy Requirements (RAR) associated with serving its customers. These rules also apply to all electricity suppliers and require operating and planning reserves of 15-17% in excess of load. In addition, these requirements will require demonstration of compliance with the rules for the future year's summer peak demand, also under consideration are specific resource adequacy rules for LSEs serving specific resource constrained areas. San Francisco is currently a

[3] D. 04-12-046 imposed a 2.0 cents/kWh CRS for all CCA customers for an 18 month period. This will effectively be reduced to a new 1.8 cents/kWh charge for PG&E customers who are served by a CCA since PG&E already charges approximately 0.2 cents/kWh for CTC that will be eliminated for CCA customers.
[4] For example limiting the wind resources to the Altamont region.

resource-constrained area therefore any CCSF CCA might have to demonstrate specific in-city resources to serve CCA customers. These rules will have a significant impact CCA resource planning and ultimately generation rates for CCA customers.

PG&E is increasingly likely to contract for electricity supply by developing a portfolio of resources types and contract lengths, as well as ownership structures. This PG&E risk diversification strategy will set the competitive context for CCA product development and resource planning.

An option available to CCSF is municipal financing. Prop H bonds could offer lower cost debt than would be available to a commercial power plant developer. This cost advantage may be magnified if wholesale natural gas prices remain high or go higher. As long as gas prices are high enough that electricity produced by gas-fired power plants is more expensive than electricity produced at wind plants, for example, wind plants will be able to sell their electricity at the marginal price of power – the gas-fired price. In those circumstances, cost-based wind power generated from municipally financed facilities may be attractive enough to outweigh the risks of long-term power plant ownership or leasing. The other attractive aspect of wind plant ownership, or long-term leasing, is the lack of fuel risk, both on price and physical delivery.

The detailed results of the resource economic analysis and bond financing options are available in Chapter 4: Resource Mix and Cost.

3.3 CCA Supplier Contracting Will Set the Framework for CCA Products

CCSF will be a major customer for an ESP, assuming that a single ESP contract is signed for CCA service.[5] CCSF is larger than the single largest customer served under DA today: University of California/California State Universities. Thus, CCSF is likely to receive considerable interest from ESPs and potentially other suppliers who would like to win this contract. However, the ratesetting policies established by CCSF will need to be designed to match what is achievable in the market at the time of a solicitation. It is possible that market limitations will also factor into ratesetting constraints.

Key concerns to the supplier will be the frequency of rate adjustments, the assignment of risk of mismatch of rates and costs if rate changes occur, and the linkage of the cost of power to energy efficiency, demand response, and renewables policies, including availability of Public Purpose Program funds to support these activities.

Ideally, CCSF decisions on ratesetting goals, customer approach, resource planning, and product line will be in place before an RFP is released. Another major decision required prior to establishing the RFP approach is to determine the level of service requested from a supplier. Will the supplier perform all retail functions, with only contract management performed by CCSF? Or, would CCSF prefer to adopt a business model that more closely matches the water and sewer service in San Francisco? The issues related to

[5] CCSF is not limited to contracting with an ESP for CCA service.

different organizational arrangements are discussed in Chapter 7 Organizational Scenarios.
Ultimately, the ratesetting goals established by the Board of Supervisors will determine what model is used for the supplier RFP. For example at one end of the spectrum, some large energy buyers provide their energy usage history by customer category in an electric supply RFP and ask for the best price for each category. The winning bid sets the rate for that category. On the other end of the spectrum, customers can identify an index on which to peg rates as well as the rate structure desired – for example a percentage discount off of each customer's PG&E rate schedule. To the extent that the constraints established by such an approach create risk, the price of risk mitigation to meet proposed contract terms will be factored into RFP bid responses.

A detailed discussion of RFP development for supplier services, including examples from other areas can be found in the Chapter 6: Solicitation and Contracting Options.

4. CCA RATE DESIGN WILL HAVE TO BE DYNAMIC

Establishing ratesetting goals is a key decision to be made before moving forward with CCA. As described above, the customers to be served and their preferences, resource planning rules and CCA resource preferences, the limitations of supplier contracting and PG&E billing, as well as the uncertainty in any of those areas that must be accommodated, will impact rates to varying degrees. Rate design is likely to be an iterative and circular process: taking all rules, constraints and preferences into account, calculating what total revenue is required, what allocation between customers is fair and how that will compare with other customer options. If the result is that what the CCA can offer is unattractive for some or all customers relative to competitive options, changing CCA preferences, releasing constraints, and changing rules should be pursued.

4.1 Challenges to matching PG&E's rates

The utilities in California no longer provide an open-book review of their resource mix and power contract terms. Nor is CPUC customer rate allocation precisely predictable. PG&E is embarking on two major contracting initiatives for thousands of megawatts (MW) of power. These new contracts will impact that utility's costs and ultimately their rates. As a result, predicting the rates charged to each customer class years in the future is risky and asking the supplier to assume that risk will increase the cost of electricity supply. In addition, CCSF will never exactly mimic PG&E's customer mix and thus even if total rates could be matched, rate allocation between customer classes will not be identical.

Due to the uncertainty related to PG&E's rates in the future, requiring a supplier to provide power in a manner that very closely matches PG&E's generation rates, for multiple years, for all customer classes may well result in increased costs for all customers. Higher rates will increase the probability that significant numbers of business customers will opt-out of CCA. This results in a feedback loop where more opt-outs

from higher revenue customers leads to higher rates for remaining customers that opt-out in increasing numbers. This possibility illuminates the rationale for permitting rate-setting flexibility that allows for special rates for large customers, which in turn reduces opt-outs, and thereby results in improved CCA rates for all customers.

While the relationship between the cost of CCSF CCA generation service and that of PG&E is not the only policy consideration for CCA ratesetting, it is likely to be an important factor in attracting and retaining CCA participation. If maintaining a link between CCSF rates and PG&E rates were a ratesetting priority, CCSF supply rates would need to change every time PG&E rates change.

PG&E rate or revenue changes are often consolidated to happen at one time, e.g. the beginning of year. Depending on the nature of the CCSF contract with its supplier, CCSF's CCA generation costs may vary more often than annually.[6] If the supplier is willing to accept annual changes in its contract with CCSF, then the timing of PG&E and CCA rate changes should track reasonably well most of the time. If not, a) there would be a need for at least an annual true-up to be sure that CCSF revenues from changing rates match costs over time; this could become an annual cost and rate review, and b) there would need to be a mechanism for assuring that the risk of any under- or over-recovery of generation rates (both gross and net) is appropriately assigned.

Under AB 57, which established the long-term power purchasing plans for utilities, PG&E is required to contract for its power needs on a portfolio basis, with a modest amount of short-term and mid-term purchases relative to their entire power generation portfolio. This resource structure means that PG&E can keep its rates fairly stable from year to year. Even if some of its contracts for new gas-fired generation are tied to gas price indices, PG&E's portfolio of hydropower and nuclear (under CPUC cost of service) and, renewable and other resources which may be under long-term, fixed priced contracts will dampen the rate impact of gas or electricity market price volatility.[7] In addition, the utility can track any shortfall, or excess, in a balancing account, collecting interest, and roll the adjustment into rates the following year.

If CCSF were to match or index to PG&E's rates, it will have to contract for resources in a manner to match PG&E's resource portfolio, which may be difficult depending on the level of confidentiality applied to PG&E's purchases. To the extent that the CCSF takes on more price risk than does PG&E, its CCA customers could benefit from better prices under some circumstances, or be burdened with worse prices under other conditions. For example, a portfolio with a higher proportion of fixed-price renewable resources than PG&E's portfolio could offer customers a discount to PG&E's rates in conditions of high gas prices. However, under sustained, low gas prices, CCSF's CCA customers could end up with higher rates.

[6] For example, such contracts may have prices tied to monthly electric price indices.

[7] In contrast, after restructuring and before the California Energy Crisis, the utilities bought all of their power from the spot market and the generation component of their rates tracked that spot market price so that the dampening effect of owned or contracted resources was not captured in rates.

To minimize the risk of losing alignment with PG&E's rates (either positively or negatively) CCSF could make an arrangement with its supplier to track the variation of the suppliers costs compared to the rate revenue received, and charge interest on the balance for later recovery, or CCSF could take financial responsibility for the mismatch between costs and rates. If CCSF wishes to minimize the risk of a mismatch between costs and revenues, it can adjust its generation rates to match its supplier contract charges and terms, but this might increase volatility in its generation rates unless the supplier contract has a fixed price. While customers have recently been exposed to varying natural gas prices on utility bills, their electric rates have been far more stable.

Regular reviews of costs and revenues are critical; to be sure that there is no revenue shortfall. In general, there is an advantage to an annual- or biennial-only review of rates and revenues insofar as such reviews are time-consuming and costly, particularly with significant public participation. On the other hand, having only annual or biannual reviews may be difficult if there is considerable cost instability and the mismatch between costs and revenues grows. There could be a trigger mechanism whereby a review is undertaken more often that annually if the mismatch exceeds a certain percentage of the balance, similar to the one that the CPUC has for utility generation costs and rates. It may also be possible to develop a hedging strategy for generation cost variability that could be pursued by either CCSF or the supplier, but hedges also have costs. Finally the CCA should also investigate the opportunity to also levy exit-fees on customers who leave the CCA after the opt-out period has finished. In terms of overall investment strategy the CCA is in the same position as an IOU. It has to make investments for the future and yet the customer base to recover the costs of such fixed investments could be variable. While the switching rules to be developed in Phase 2 of the CPUC CCA proceeding might well reduce the amount of customer switching from the CCA an exit-fee approach is a backstop strategy. exit-fees could be established e.g. as a "quid pro quo" on large customer contracts. That is if large customers were guaranteed a three or four year set electric rate but choose during that period to leave the CCA then the CCA could establish an exit-fee to make the remaining CCA customers whole. This operates on the same principal as the CCA customers paying a CRS charge.

4.2 Treatment of Low-Income Customers Requires Special Consideration

A key aspect of residential rates regulated by the CPUC is the California Alternative Rates for Energy program (CARE). As discussed briefly in Chapter 2, this program applies to residential customers of PG&E and other investor-owned utilities and provides about a 40% discount from average total residential bills for customers with incomes up to 175% of the Federal poverty line. In CCSF about 17% of residential customers are currently *participating* in CARE.[8] This is slightly lower than the 21% of PG&E's residential customers that are participating in CARE system-wide. Moreover, according to PG&E the CARE program has a higher penetration rate in San Francisco (82%) than it does on average throughout PG&E's system (70%). This means that there are fewer customers eligible for CARE and not participating in the program in San Francisco than

[8] Customers who qualify for medical baseline allowances also receive electricity at the same discount as CARE customers.

in the rest of PG&E's service territory. Within CCSF these customers currently have average monthly bills of $26.27 of which $8.79, or 33% is constituted by the generation portion. Assuming the CCA would offer CARE rates identical to those offered by PG&E this might require, at least in the early years, a discount higher than the 40% currently offered by PG&E.[9] It is currently unclear from CPUC proceedings whether the subsidy for the CARE discount will be the responsibility of all of PG&E customers regardless of the generation supplier – this would make the CARE program CCA revenue neutral and will be addressed in Phase 2 of the CCA proceeding. However, the impact on CCA revenue of the CCA offering both the CARE discount, and the source of recovery of any revenue shortfall associated with CARE may have an impact on CCA rates.[10]

4.3 CCA Faces Billing Constraints In Setting Rates

By law, CCAs will use existing utility billing systems. Thus, PG&E will be billing CCA customers on a monthly basis probably using PG&E's rate-ready billing option already used by some ESPs for direct access. CCSF will provide PG&E electric generation rates (and where appropriate electric demand charges) for each rate schedule the CCA serves. This rate ready billing option currently costs 70 cents/bill/month. For CCSF as a CCA the yearly cost of using this approach is about $2.6 million (assuming zero opt-out of CCA).

This approach is simple and means that a customer will not receive a new bill due to CCA. However, the rate-ready billing method limits the options for CCA ratesetting to rates designs which can be implemented within the current PG&E billing system.

5. CCA PHASE-IN IS AN IMPLEMENTATION OPTION

In its Phase 1 CCA decision, the CPUC provides an option for CCSF to phase-in its CCA load.[11] This would mean that CCSF would be able to add groups of CCA customers over an agreed period of time – probably 6-12 months. A phase-in would give CCSF the opportunity to implement its CCA program more slowly, in order to work out any implementation difficulties. However, a phase-in will also significantly increase the operational complication of opting-out and mass communication efforts. Whether or not to take advantage of the phase-in option will require review during detailed implementation planning and a decision made before developing an RFP, designing rates and committing to electricity purchases.

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[9] Issues related to low-income discounts and CCA implementation are also a Phase 2 issue before the CPUC.

[10] A March 22, 2005 Draft CPUC Decision on Low-Income Programs in R.04-01-006 shows that the Public Goods Surcharge Program for PG&E will allocate about $198.5 million for CARE subsidies – some portion of that PGC funding should be available to CCSF to offer a CARE Program.

[11] D.04-12-046 ibid, p.54/55.

If CCSF wishes to use a phase-in approach, it might have to consider the order of customers to serve (including numbers and customer classes) and the pace of phase in. It could set annual limits based on the number of MW, the number of customers within a class, the customer class, the type of customer (e.g. bundled, or DA), the annual amount of revenue at stake, or on other criteria. Phase-In is further discussed in Chapter 7 Organizational Scenarios.

6. PG&E'S RATESETTING PROCESS AT THE CPUC

PG&E rates are set under the CPUC ratemaking process. First, PG&E's revenue requirement for a future time period is set based on the forecasted cost to serve its forecasted demand for power over that period of time. The annual revenue requirement is the amount of money that PG&E must collect through billing its customers over a year, including capital costs, variable costs (including fuel and O&M), contract costs, taxes, and return on investment. The proceeding in which the revenue requirement is determined is called Phase 1 of a General Rate Case (GRC).

The revenue requirement is allocated over PG&E's forecast sales in Phase 2 of the GRC to determine the average rate that must be paid by each class or rate schedule of customers in order to produce that amount of revenue. Since it is spread over *forecast* sales, the amount of revenue actually collected will never exactly equal the revenue requirement. Excesses or shortfalls in revenue are tracked and applied to adjust the revenue requirement for the following year. PG&E is also authorized annual revenue requirement adjustments for inflation and capital additions, called attrition adjustments.

Separately, PG&E has an annual review of its generation costs, with annual rate adjustments. More frequent adjustments are permitted if its costs and revenues diverge by more than five percent.

Once the revenue requirement is determined, it is allocated among customer classes and rate schedules within the customer classes.[12] The basic framework for this allocation is set every three years in Phase 2 of GRC. The revenues to be collected are allocated among the various customer classes based on the marginal cost of serving the different classes. Next, revenues to be collected within a class are allocated to rate schedules within each class. Once the revenues have been allocated, rates are set such that the usage characteristics expected of the sales for that group of customers, when multiplied by the rates, will produce the desired amount of revenue.

Some classes, like residential, simply have charges per kWh of usage. Others also have demand charges, based on the maximum instantaneous demand of a given customer over a month, or the maximum demand during the peak period of system demand. Some have time-of-use rates, where the kWh charges vary by time of day. Lastly, some customer

[12] For example, a customer class might be residential, industrial or agricultural. A rate schedule is a specific set of rates for a group of customers within that class. For example, a residential customer could be on a basic domestic rate schedule or a time-of-use rate schedule.

classes pay customer charges, which are fixed charges per month designed to capture the fixed costs of serving the customer, like metering and billing.

For the purpose of CCA service, the key factor for CCSF is allocation of revenues to recover supply costs, since PG&E's delivery, metering and billing costs are included in PG&E delivery charges. PG&E's generation costs include the utility's own generation costs from its power plants and purchased power contracts, as well as a share of DWR contract costs, as determined by the CPUC through its allocation methodology for DWR power contracts.

The utility must also recover other generation related costs like CTC and DWR Bond Charges from *all* customers, including CCA and non-exempt DA customers, as part of its delivery charges. In the case of a CCA, its generation costs will be those of the supplier contract plus the CRS charged to CCA customers by PG&E. This is why CCAs have to account for the CRS charge in their economic evaluation since this is a new rate component that CCA customers will be paying. A CCA may also include additional costs incurred for energy efficiency, demand response, or renewables acquisition undertaken by CCSF itself, as opposed to by its supplier, in it generation rates.

Generation-related costs for utilities are recovered using demand and energy charges for larger customers and energy charges for smaller customers. As noted above, CCSF will have to decide whether to model its generation rates after those of PG&E, i.e. with demand and energy charges, often varying by time of use, for appropriate customers, or whether to model its rates after the charges imposed by its supplier, which may only be energy-related (i.e. volumetric) charges.

CCSF will also have to decide how to adjust its rates in relation to rate adjustments by PG&E. This was discussed somewhat above. CCSF will have to decide whether to make its generation rate changes at the same time as PG&E makes generation rate charge changes, even if its costs change on a different schedule, and how to handle the pass-through of its own cost changes resulting from its suppliers s billing on the same or a different schedule.

7. PG&E'S GRC Phase 2 Revenue Allocation and Rate Proposal. [13]

PG&E's Phase 2 proceeding is underway at the CPUC and expected to be decided by the Commission by the end of 2005. PG&E has indicated that it would like to settle this proceeding. There will be active participation from residential, commercial, industrial, agricultural, and street-lighting customers, the latter of which are cities and counties. PG&E's revenue allocation proposal is to increase residential revenue allocation, maintain small business customers close to current revenue allocation, and provide a sizable decrease for the majority of medium and large customers (with the exception of standby customers who would see a revenue allocation increase).

[13] This section of the report was written prior to the February 18, PG&E GRC Phase 2 Rate Update.

Compared to 2004 energy generation charges this overall revenue allocation proposal translates into energy generation charges which are: increased across the board for residential customers including CARE customers, slightly decreased for small commercial customers; and significantly decreased for medium commercial, large commercial, and the largest commercial/industrial customers. The overall impact of the proposed revenue allocation and rate design change is to decrease the overall generation cost to serve CCSF by half-cent/kWh or about 6%. Based on 2003 loads and early 2005 PG&E generation rates, the average generation cost to serve CCSF customers was 6.3cents/kWh. Should this PG&E GRC Phase 2 proposal be approved as filed by the CPUC this average PG&E generation cost to serve will drop to about 5.9 cents/kWh. This average generation rate would provide a formidable challenge to making CCA economic. For example, assuming an average 1. 8-cents/kWh CRS energy charge then the all-in cost to serve CCSF customers could not competitively exceed 4.1cents/kWh in 2006. The impact of the CRS charge is assessed in Chapter 4.

One of the more complex issues for PG&E's proposed rate design is how to set residential rates. This is because there are many constraints on residential rates that have been imposed by legislation and prior CPUC decisions.

The first constraint was imposed by the passage of AB 1X in January 2001. As discussed in Chapter 2, this legislation permitted *no* increase in residential rates for customer usage up to 130% of the customer's baseline amount. The baseline amount has been set in CPUC proceedings and varies by climate zone and type of energy usage in a dwelling (e.g. mix of gas and electric usage). This prohibition of any rate increase has meant that any residential rate increases must be applied to usage in excess of 130% of baseline. About 73% of PG&E's residential consumption is protected from rate increases because of this legislation and other CPUC-imposed restrictions on increases for customers receiving CARE rate (for low income customers) or on medical baseline allowances. Thus any rate increases must be imposed on only 27% of residential usage, or be shifted to other customer classes.

CCSF must decide whether or not it will maintain the rate freeze for residential customer use up to 130% of baseline usage, such that its rates for such usage by residential customers are no higher than those of PG&E. In 2003 about 77.5% of CCSF residential customers have usage below 130% of baseline. This is higher than the PG&E system average for the residential class of 73%. This means that CCSF has proportionately less residential electric consumption than PG&E available for rate increases if CCSF attempts to maintain the under 130% rates at PG&E comparable rates.

In Phase 2 of its current GRC, PG&E proposes to try to allocate the shortfall from the 130% of baseline rate-cap within the residential class. However, PG&E also proposes to cap the overall residential increase, which means some of the costs will spill over to other classes. The other classes will oppose this shift of costs in their direction. This debate in the PG&E rate proceeding illuminates how similar ratesetting issues may affect the CCA product design.

Related to the baseline rate issue, PG&E's residential customers have increasing block rates. Baseline usage sets the amount of energy in the first residential tier, while the second tier includes usage from 101% to 130% of baseline usage. There follow three tiers with increasing rates for increasing usage, with the blocks sized on the basis of the baseline quantity for the customer in its climate zone.

In the GRC Phase 2 proceeding, PG&E proposes to retain five residential tiers but establish the same rates for Tiers 4 and 5. CCSF will need to consider whether it also wants to establish a comparable tiered residential rate structure. If so, it should consider whether it wants its rate tiers to increase such that it maintains the same price differential among the residential rate tiers as does PG&E. But the rate-ready billing requirement will require that the overall structure of CCA rates fit within PG&E's billing constraints.

PG&E also makes proposals for larger customers in its Phase 2 proceeding.

- Mandatory TOU (Time of Use) rates for all customers over 500 kW
- Voluntary TOU for all smaller customers
- Choice of rate options for smaller customers, e.g. optional demand charges and/or TOU energy charge options
- Revenue neutral TOU and non-TOU rates for customers less than 500 kW
- Switch all customers above 500 kW to recording usage at 15 minute demand intervals for meters with this capability
- Increase in customer charges, with greater increases for higher voltages
- Seasonal differential in distribution related charges at 1.5 (summer): 1.0 (winter)
- TOU Ratio of summer combined distribution demand and energy charges: 2.5:1.0:0.5
- TOU Ratio of winter combined distribution demand and energy charges: 1.5:1.0
- Collect 20% of allocated generation revenue as capacity (20% through demand charges for higher voltage customers and less for lower voltage customers) with rest in TOU energy charges
- Customer charges for standby customers (which would apply to backup service for self-generation or distributed generation customers) will be the same as for full requirements customers; standby customers will also pay peak demand-related distribution revenues on a TOU kWh basis, and will pay all other generation and distribution costs as reservation charges.

Some of PG&E's large customers take interruptible service. They receive lower rates in exchange for being available to shut down their usage in case of system supply or reliability emergencies. Given its load pocket characteristics CCSF may have to investigate whether to encourage such an option for its own customers. CCSF must consider whether it would like to pay incentives and have its own program for load reductions so that it can get credit for demand response for resource planning purposes. If CCSF chooses to do so, it must decide whether or not to set its incentives at the same

level as PG&E or greater. Additionally, CCSF would have to consider whether its customers could participate in both load reduction programs, or if there could be double counting of demand reduction as a result. CCSF would also have to decide to coordinate its demand response program directly with CAISO, through its supplier, or through PG&E.

8. THE CCA PRODUCT LINE WILL IMPACT RATESETTING

CCSF may decide to pursue "demand response" rates, such as Critical Peak Pricing (CPP)[14] and Real-Time Pricing (RTP). These rate options are designed to charge high rates when supplies are tight or reliability is threatened, in the expectation that customers on these rates will reduce their usage. All of these rate options require advanced metering. Currently these meters and rates are only available to PG&E's larger customers.

The competitive landscape for demand response rates is in flux. The CPUC has ordered PG&E and other utilities to provide plans by March 15, 2005 for expanding advanced metering.[15] In addition, the CPUC has ordered PG&E to file critical peak pricing default rates for implementation in summer 2005 for all customers over 200 kW.[16]

Such rate options (e.g. interruptible, CPP, RTP) could be part of CCSF's demand response component of its resource plan, to help meet resource adequacy goals. On the other hand, the actual demand response to these rate options is speculative at the present time. Furthermore, many large customers apparently do not wish to face such rate fluctuations that would potentially lead to considerable variation in monthly bills. Would CCSF be willing to pursue such options over customer protests? CCSF might avoid these rates because its customers have less peaky load than other parts of PG&E's service territory. On the other hand, demand response is a required part of resource planning under CPUC decisions. CCSF must consider all of these factors when deciding what rate design options to pursue.

CCSF may also consider encouraging customers to engage in distributed generation (DG). If it wishes to do so, the City must also decide what, if any, types of DG to support, i.e. just using renewables, or DG just for certain sizes of customers? If it chooses to promote DG using renewables, CCSF could consider providing its own incentives for renewables, or it should be able to take advantage of the SGIP (Self-Generation Incentive Program) available from the CPUC for larger commercial and industrial customers (systems over 30 kW) or the Emerging Renewables Program (ERP) incentives for residential and small commercial self-generation provided by the CEC. Both of these programs are funded through non-bypassable charges on PG&E customer

[14] Critical peak pricing involves setting very high rates for a limited number of days per year where power supplies are most tight, as an incentive for customers to reduce consumption. Real-time pricing involves pricing incremental and decremental customer usage at wholesale market prices, either day-ahead or spot.

[15] R. 02-06-001

[16] "Ruling Directing the Filing of Rate Design Proposals for Large Customers", December 8, 2004.

bills. In addition, PG&E has also proposed the possibility of investing in self-generation equipment at customer premises. As this may be permitted by the CPUC, CCSF should decide its own reaction to this option and whether and how it would encourage PG&E investment at the premises of its CCA customers. Since CCSF's CCA operation will not own the distribution system, CCSF should consider whether it wishes to encourage self-generation that creates need for less distribution investment. CCSF could work with PG&E on this. Additionally, the CCA may wish to offer customers net-metering tariffs as this rate option is currently available from PG&E. Under net metering customers who generate their own power (up to 1 megawatt (MW) of either wind or solar generation) receive a credit from PG&E at the total rate level. Under a CCA the responsibility for this credit could be split between PG&E T&D rates and CCA generation rates.[17]

CCSF support of self-generation means it will have to have to develop a generation standby rate, in case the customer's equipment is not operational. It can follow the CPUC decisions regarding standby rates for different kinds of DG service or it can develop its own. Certainly for any DG customer, PG&E will have a standby rate for T&D service, but CCSF would provide the energy for the customer for backup and supplemental service. CCSF would have to consider how to charge for this service and whether to follow the CPUC pricing rules.

Finally, Governor Schwarzenegger has announced his Million Solar Roofs Initiative, which is embodied currently in proposed legislation under Senate Bill 1. Under the Governor's plan, the State of California would establish a new set of financial incentives to encourage residential and commercial applications of solar PV with the goal of achieving 1,000,000 solar powered residences and businesses, or the equivalent of 3000 MW of solar capacity, by 2017. CCSF should consider whether and how it would join in this initiative if it became a CCA. There has been some discussion of funding the incentives for this initiative through utility charges, so CCSF CCA customers will likely help fund it and consequently should be permitted to participate. CCSF may wish to coordinate with PG&E in developing an equitable and cooperative program.

[17] In draft PG&E CCA Tariffs PG&E has proposed that existing net-metered customers would not be automatically enrolled in the CCA program but would have to opt-in to CCA.

Community Choice Aggregation Draft Implementation Plan

Chapter 4: Resources and Costs The Economic Costs and Benefits Of Community Choice Aggregation to CCSF

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1. INTRODUCTION AND SUMMARY

1.1. Purpose and scope of study

California law allows municipalities to become the default procurer of electricity for their residents, businesses, and institutions, replacing the incumbent investor-owned utility, under a program known as Community Choice Aggregation (CCA).[1] The City and County of San Francisco (CCSF or City) is undertaking an extensive review and analysis of the major aspects and potential implications of Community Choice Aggregation, to evaluate the desirability of forming such a program in CCSF. As part of this overall effort, the City has engaged Altos Management Partners Inc. (Altos) to evaluate the potential economic costs and benefits of a Community Choice Aggregation program. This report summarizes Altos' efforts on this project.

There are several basic economic issues to be examined. First, can a municipality (through CCA) procure electricity – either through contracts or through ownership of generation facilities – at prices lower than or competitive with the incumbent utility? The municipality has at least two potential economic advantages over an investor-owned generator: access to lower-cost capital using greater leverage and municipally-financed bonds, and no federal/state income taxes (since there would presumably be no "earnings"). These cost advantages are potentially very significant with respect to any large-scale renewable generation (i.e., wind-power) that a municipality might develop. Second, if the CCA option appears more expensive, it is important to quantify the difference in cost, as part of analyzing whether the added potential benefits of CCA – local control, opportunities for "greener" power generation, etc. – are worth the extra cost.

As requested by the San Francisco Public Utilities Commission (SFPUC) and San Francisco Environment (collectively, the Departments), Altos' concentrated on two main areas of analysis. First, Altos has prepared a comprehensive quantitative analysis of the potential costs and benefits of a CCA program for CCSF, as compared to continued electricity procurement service from PG&E. This quantitative analysis comprises the bulk of this report. Second, Altos also prepared a critical analysis of the R.W. Beck study on Community Choice Aggregation submitted to the San Francisco Local Agency Formation Commission (LAFCO) on August 6, 2003. This critique appears in Section 5 of this report.

As part of this project, Altos has developed, utilized, and delivered to the City two sophisticated computer models that provide the quantitative analytical horsepower for the CCA v. PG&E cost comparison. The first computer model is a version of Altos' North American Regional Electric (NARE) Model, a fundamentals-based simulation model of western electricity markets.[2] This NARE Model is used to forecast market-clearing

[1] Under Community Choice Aggregation, the municipality would be responsible only for power procurement. Transmission and distribution would remain the responsibility of the incumbent utility.
[2] A more detailed description of the NARE Model appears Section 4 of this report.

electricity prices, an important input into the forecast of a CCSF Community Choice Aggregator's cost of power. As part of this project, CCSF has been granted a one-year license for the MarketBuilder™ software on which the NARE Model runs.[3] Second, Altos developed a Contract-Mix Model that performs the CCA v. PG&E cost comparison and provides graphical and tabular summary outputs. The Contract-Mix Model was developed using Microsoft® Excel and Access software, which is currently resident on CCSF computers. As part of this project, SFPUC staff will be trained in the use and operation of these computer models. With these tools, CCSF will be able to further refine and extend the analysis described herein, and to examine the potential impacts of alternative electricity and energy market scenarios, new information as it develops, and alternative regulatory regimes.

The analysis that follows is a best-efforts study of the potential economic outcomes if the City becomes a CCA. There can be, of course, no guarantee that if CCSF becomes a CCA that any particular outcome described herein will be attained. Actual, realized economic costs and benefits will be determined by the success of a CCSF Request For Proposals with an Electric Service Provider (ESP) or other electric supplier, the subsequent market performance of the supplier, and a whole host of market factors and variables that are beyond the control of the supplier and CCSF, e.g. regulatory decisions of the CPUC, fuel prices, federal and/or state environmental regulations, etc. Nonetheless, this analysis and the computer simulation tools now available to the City provide the solid quantitative footing for informed decision-making and the starting points for a risk analysis of creating a CCA in the City.

1.2. Summary of Results and Lessons Learned

This study has produced a number of important insights and conclusions about the potential economic/financial impacts of a move toward Community Choice Aggregation by the City and County of San Francisco. These insights and conclusions are presented briefly in this section, and then described more fully in the following sections of this report.

Community Choice Aggregation could potentially provide benefits to CCSF, in the form of lower power acquisition costs than might be available from PG&E. However, this favorable outcome is by no means guaranteed. Of the 60 scenario cases we investigated, only 14 provided any measure of economic benefit.

The potential economic benefit of CCA is limited, even in the favorable cases. The "best case" scenario results in savings of about 8% over the thirty-year forecast horizon. On a Net Present Value basis, the best cases produced benefits in the range of $100 million to $300 million for the 30-year time horizon, on a total projected expenditure for power acquisition of about $7 billion to $8 billion. However, the unfavorable cases can result in CCA power acquisition costs that could reach 25% to 35% higher than continued

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[3] After the first year, CCSF may license the MarketBuilder™ software from Marketpoint Inc. (an affiliate of Altos) under normal commercial terms.

service from PG&E. In these cases, the NPV could reach -$200 million to $-600 million or more.

The potentially most favorable scenarios for the CCA are those in which the CCA builds a "shaped wind" resource for its peak power needs, but buys its baseload power from third-parties in the WECC market. Baseload power – generally available from low-cost coal, hydro, and nuclear sources throughout the WECC -- is projected to be readily available at reasonable prices throughout the forecast horizon. Any potential CCA-owned generation resources constructed to deliver baseload power – either wind-based or gas-fired – cannot compete on an economic basis with these other supplies and should not be pursued. However, a CCA-owned "shaped wind" resource can potentially compete in the peak power market, and this resource could provide economic benefits to a CCSF CCA.

The most critical factor in the potential economic success of a CCA will be its power contracting outcomes. If the CCA is able to consistently contract for power products at prices that are at the low end of the reasonable range for these products, the CCA can potentially achieve lower power costs than PG&E. All 14 of the potentially favorable cases we identified shared this characteristic. However, if the CCA cannot achieve these superior contracting outcomes consistently over the 30-year forecast horizon, the CCA will run the risk of unfavorable outcomes relative to continued service from PG&E. Indeed, all of the cases we examined with less-than-superior contracting outcomes resulted in significant financial costs to the CCA.

Even in the favorable cases, the CCA would have to endure a cumulative deficit of about $65 million to about $130 million, due almost exclusively to the CPUC-imposed Customer Responsibility Surcharge (CRS). The CRS is one regulatory price that must be paid to form and operate a CCA program. This early-year deficit is a characteristic of every case we examined, due to the high per-kWh level of the CRS in 2006-2007. In the favorable cases, the CCA is projected able to achieve lower costs than PG&E and thereby reverse this deficit and eventually produce positive benefits. In the unfavorable cases, this early year deficit continues for the remainder of the forecast horizon, as the CCA continues to achieve higher generation costs than PG&E.

"Opt out" by the larger CCSF electricity consumers presents a substantial risk to the economic success of a CCA. Virtually all of the cases we examined that posited significant "opt out" by CCSF's larger commercial and industrial electricity customers resulted in unfavorable outcomes for the CCA. These customers have the highest generation cost component in their current and projected PG&E rates. With all of these customers in the CCA, the average cost per kWh that the CCA must achieve in order to "beat" the PG&E rates is relatively high. If these customers leave the CCA, the average PG&E generation rate for the remaining CCA customers is reduced, so the CCA would have to achieve even lower costs to "beat" it. However, there are lower limits to the generation costs that can potentially be achieved by the CCA.

If the CPUC-mandated Renewable Portfolio Standards (RPS) requires the CCA to purchase renewable power at high "market referent prices," the potential financial attractiveness of the CCA option would likely disappear. If separate markets develop for renewable power to meet RPS standards, the CPUC is contemplating establishing prices for these resources at relatively high "market referent prices." If the CCA is required to purchase some of these resources to meet the RPS, these higher-priced supplies would replace lower-cost, market-priced supplies, and thus seriously undermine the potential economic benefits of the CCA option v. the PG&E option.

Conservation efforts by CCSF will reduce overall spending on power, but the impact on the average price of power is not necessarily a reduction. A reduction in CCSF power demand through conservation efforts will also affect the supply of power in California, and it the combination of these demand effects and these supply effects that will determine the prices in the market. Our NARE Model results indicate a very slight rise in prices due to conservation, as generators respond by building less of the new, lowest-cost generation and continuing to use more of the older, more-costly equipment.

Altos' forecast of the average PG&E generation rate component is very close to that of SFPUC for the period 2006-2013; after that Altos projects PG&E's generation rates increasing faster than SFPUC projects.[4] Altos' projection is based on an integrated and internally consistent analysis of PG&E's known and anticipated costs as well as forecasted purchases. This forecast is highly dependent on assumptions about natural gas prices and PG&E's power contracting outcomes. Using a higher forecast of PG&E generation rates yields more favorable economic results for the CCA in the overall CCA v. PG&E cost comparison.

The CCA's operational costs and other generation-related costs are a very small part of the CCA v. PG&E cost comparison. Our analysis shows that the two most important factors in determining the economic success of the CCA will be its contracting outcomes and the CRS. In particular, if the CCA's contracting outcomes are not superior, nothing the CCA does with respect to its other costs will affect the overall economic outcome.

The R.W. Beck study delivered to LAFCO in 2003 makes mostly non-quantitative statements about potential benefits and risks of a CCA program. While R.W. Beck's economic analysis certainly identifies many of the important issues to be considered, it cannot, in its current form, meet the needs of CCSF for comprehensive, quantitative, and insightful analysis of the potential economic impacts of a CCA program. In addition, market and regulatory events have advanced and new information has been revealed, so the R.W. Beck study is now somewhat stale, due to the passage of time.

[4] The SFPUC forecast is based on a Navigant Consulting forecast – see below.

2. ECONOMIC COSTS AND BENEFITS OF CCA

2.1. <u>Analysis Methodology</u>

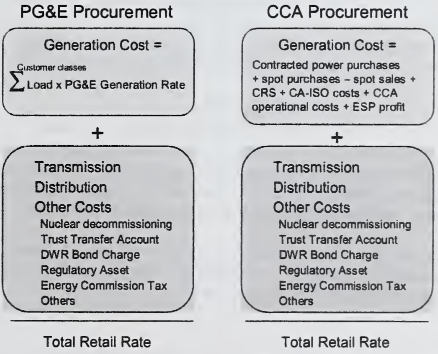
The economic analysis of the costs and benefits of a CCA program for the City is relatively straightforward. The basic idea is to compare, on an "apples to apples" basis, the costs that CCSF customers would incur for electricity service in two circumstances:

1. Continued fully-bundled service from PG&E

2. Electricity procurement from a CCA

In either case, CCSF customers would continue to receive electric transmission and distribution service from PG&E, so the sole focus of this analysis is on the costs of generation and related costs. The idea is to capture, for each service option -- PG&E and CCA -- all of the costs <u>except</u> transmission and distribution (and certain other non-generation costs), which will be the same in either case. The relevant cost comparison is presented in <u>Figure 1</u>~~Figure 1~~ below. Each side of the figure lists all of the costs that comprise a customer's total retail rate. Since the lower boxes are the same regardless of which entity procures the electricity, the cost comparison focuses solely on the costs in the upper boxes.

Figure 1. CCA v. PG&E Cost Comparison[5]



[5] A portion of PG&E's generation costs are recovered in time-of-use demand charges on rate schedules for larger customers. For purposes of this analysis these demand charges have been converted to a dollars/MWh basis.

In the Contract Mix Model developed for CCSF, these cost comparisons are presented year by year (2005-2035) in total dollars, in \$/MWh, and in cents/kWh. The cost comparison is also available for the 30-year totals. In addition, the comparison can be presented in constant dollars, in nominal dollars ("dollars of the day"), and in net present value (NPV) terms.

2.1.1. Forecasted PG&E Generation Rates

One side of the cost comparison is the case in which San Francisco electricity customers continue to receive fully bundled service from PG&E. The meaningful value for cost here is the cost of electricity generation. Since the advent of electricity market restructuring in California in 1998, PG&E and other electric utilities have been required to "unbundle" (or segregate) their generation-related costs from their other costs (transmission and distribution), and each customer's retail billing statement separately indicates the charges for electricity generation. This "generation rate component" is generally expressed on the bills in cents per kilowatt-hour (cents/kWh), and this single rate reflects each customer's full allocation of generation-related costs. Due to certain legislative and regulatory requirements, the different classes of customers – residential, commercial, industrial, etc. – may have different per-unit generation components in their bills.

For the PG&E option then, the total generation cost will be equal to the product of the electricity load (in kWh, measured at the customers' meters) and the PG&E per-unit retail generation rate component (in cents/kWh) plus, depending upon rate schedule, a time-of-use demand charge which recovers some generation costs. In this analysis, these demand charges have been converted to cents/kWh equivalents. If we happen to know the different PG&E retail generation rate components by customer class, we have to segregate the power load by customer class and calculate as follows:

$$\text{Total cost} = \sum^{\text{All Customer classes}} \text{Generation Rate x Customer Class Load}$$

With this total cost, we can compute an average cost over all CCSF load, assuming continued service from PG&E. If we have just an average PG&E generation cost component, we simply multiply that average rate by the total load.

The cost comparison is on a prospective basis, so a forecast of these PG&E generation rate components is necessary. For this project, SFPUC provided an existing forecast of PG&E generation rates, by customer class.[6]

[6] This forecast was prepared by Navigant Consulting in August, 2004. This forecast was self-contained, and therefore Altos makes no comment on the reliability or validity of this forecast. However the SFPUC set the 2006 PG&E rate forecast and the overall trajectory of PG&E's rates using the Navigant escalation factors. As part of this analysis, Altos has prepared its own forecast of the average PG&E generation rate (see Section 2.2.7).

These generation rates are assumed to be "all in," that is, we assume they include:

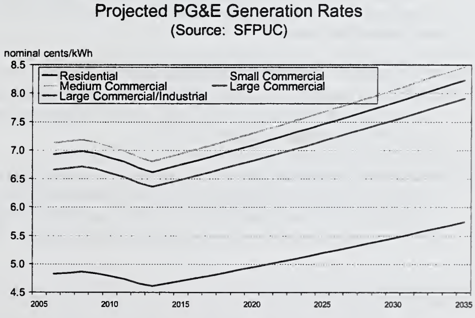
- the costs of transmission and generation losses (the "extra" kWh that must be purchased to compensate for these losses);
- costs related to resource adequacy requirements (i.e., a reserve margin at peak load times); and
- long-term contract costs allocated to customers remaining with PG&E for electricity procurement service.

These PG&E generation rate forecasts are presented in Figure 2~~Figure 2~~.

The forecasted PG&E generation rates thus represent the benchmark for the CCA v. PG&E cost comparison. A CCA could be the less expensive option for CCSF customers if its generation-related costs are, on an average unit basis, projected to be lower than PG&E's.

As part of this project, Altos prepared for CCSF an alternative forecast of PG&E generation costs (on an average basis, not differentiated by customer class), presented in Section 2.2.7 of this report.

Figure 2. Projected PG&E Generation Rates



2.1.2. CCA generation-related costs

On the other side of the cost comparison are the CCA's generation-related costs. As seen in Figure 1~~Figure 1~~ above, these costs include a different set of components than PG&E's

all-inclusive generation rates. First and foremost are the CCA's actual costs of procured power. These costs will include the prices paid to third parties for contracted power and any spot purchases, as well as the direct costs of power from any CCA-owned generation facilities. The calculation must specifically account for transmission/distribution losses and resource adequacy requirements. In addition, there are other costs that arise from the creation of the CCA that must be factored into the cost comparison. These other costs are identified briefly here (and discussed more fully in other sections of the overall study).

- Customer Responsibility Surcharge (CRS). The CRS is a CPUC-imposed fee specifically levied on CCA customers that is designed to compensate the incumbent utilities' remaining (i.e., non-CCA) customers for the costs of contracts for power that become surplus to the utilities due to the loads departing to CCAs. It is a regulatory cost of leaving the incumbent and electing service from the CCA.

- PG&E Billing Costs. Under proposed CPUC regulations, CCA customers would continue to receive their electric bills from PG&E, but the CCA would make arrangements with PG&E for the bill to specify the CCA charges, and also PG&E would remit the payments for generation to the CCA. CPUC regulations will permit PG&E to receive payment from the CCA for these services.

- CCA Administration Costs. The CCA itself will have certain ongoing costs that will have to be recovered from customers, including the costs of administration and a call center. In addition, there will likely be some one-time start-up costs.

- CA-ISO Charges. The California Independent System Operator imposes charges for ancillary services on all ESPs. These charges are typically recovered from generators or other load serving entities, so the CCA would be responsible for these costs as well.

- ESP profit. We assume the City would, at least initially, contract with an Energy Service Provider (ESP) for the power procurement for the CCA. This ESP will almost certainly be a for-profit enterprise, so the costs to the CCA and its customers must include some level of profit for the ESP.

2.1.3. The Contract-Mix Model

The Contract Mix Model is a spreadsheet/database tool that performs the CCA v. PG&E cost comparison, taking into account all of the relevant costs on both sides. A central feature of the Contract Mix Model allows evaluation of a CCA's alternative power

procurement strategies and scenarios.[7] Procurement of electric power supplies typically includes purchases of contract power products (usually at fixed prices) as well as spot power (whose price may vary on an hourly basis). The model assumes that there will be two types of contract electricity products available. These two contract products – a 7x24 off-peak product and a 6x16 on-peak product – are generally available in the market today, on a month-to-month (or longer) basis. The 7x24 off-peak product is for baseload power: 24 hours a day, 7 days a week. The 6x16 on-peak product is available Monday through Saturday, 8AM through midnight. This availability of this 6x16 product is defined on a weekly basis as 54 percent (96 / 178). These contract power products will be available from independent parties ("contract power") or the CCA could build resources that would provide either baseload or peak power ("CCA-owned resources").

At the direction of SFPUC Staff, our first cut analysis assumed that the CCA will have two choices for owned resources: new, combined-cycle gas turbines for 7x24 off-peak power and a "shaped" wind resource for 6x16 on-peak power. Due to the intermittent nature of wind power generation, it is generally not competitive in the off-peak hours, but it is potentially competitive in the market as an on-peak product, when "shaped" by another generator (either hydro-electric or gas-fired).[8] Our "base case" assumptions for the cost of CCA-owned power are as follows: for 7x24 power, 1.83 cents/kWh[9] plus the cost of natural gas fuel; for 6x16 power, 4.8 cents/kWh for shaped wind power (4.2 cents/kWh for the wind power and 0.6 cents/kWh for the shaping service). The Contract Mix Model allows the user to specify alternative costs for these CCA-owned resources. In addition to contracted or CCA-owned supplies, "spot" power is available any hour of the day, at a price determined in the marketplace.

Also at the direction of SFPUC Staff (and late in the course of the assignment) we modified the Contract Mix Model to accommodate a third contract power product available in the marketplace: a "super- peak" block of power (5 days a week, 8 hours a day), assumed to be a renewable resource that would be priced at a CPUC-mandated "market referent price."

The prices paid by the CCA for any of these power supplies reflect the price at the generation stage, i.e., a buyer will have to pay transmission and distribution charges (plus other miscellaneous charges and fees) to get the power to his/her meter.

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[7] Given the experience of 2000-2001, it is not expected that a CCSF CCA would rely exclusively on "spot market" power. Indeed, the evolving CPUC regulations for resource adequacy for all Load Serving Entities (LSE), including CCAs, will require a significant amount of forward contracting by CCAs.

[8] In a shaping arrangement, the intermittent nature of wind power is "firmed up" for the entire 6x16 period by another generator, at an additional cost. These shaping arrangements appear to be readily available in the market. For more information, see the following web-sites: http://www.nwcouncil.org/energy/powersupply/wind workshop 2003_12/2003_12/Mainzer_Planning_Council_Presentation_120503.ppt and http://www.iea.org/dbtw-wpd/textbase/work/2004/nea/lyons.pdf.

[9] This levelized cost is based on an assumed capital cost of about $750 per KW and a heat rate of about 7000 Btu/kWh.

The Contract Mix model allows the user to specify the amounts of electricity the CCA would procure from each of these "products." In addition, the user can make assumptions about the potential prices of these products, from the NARE Model electricity price projections, to arrive at the total projected cost of CCA power. If the CCA is projected to be "long" power at any hour (i.e., contracted power exceeds the CCA load), the model assumes that these excess power supplies are sold back to the market at the "spot" price and these revenues offset the CCA's expenditures for power. The Contract Mix Model is described in much greater detail below and in Section 3 of this report.

2.1.4. The NARE Model's Projected Power Prices

The projected power prices from the NARE Model form the basis for the projections of the cost of power that the CCA would contract from third parties. The forecasted price outputs from the NARE model are in the form of ten (10) prices per month. Each forecasted price represents the market-clearing power price for a portion of the hours each month, from the highest-price peak hours (representing one-percent of the hours, or about 7 hours) to the lowest-price "base" hours (representing 2 percent of the hours, or about 15 hours). The allocation of hours to the ten price tranches is shown in Table 1~~Table 1~~ and an illustrative graph showing the projected prices for a month is shown in Figure 3~~Figure 3~~. Please note that the hours in a price tranche within a month will not necessarily be continuous in chronological time. For example, Tranche One captures the price of the 7 highest-priced hours in a month, regardless of when they occur in the month. For a representative September, say, these highest-priced hours are likely to occur in the late afternoon on the seven warmest weekdays in the month, and not during a continuous seven-hour period.

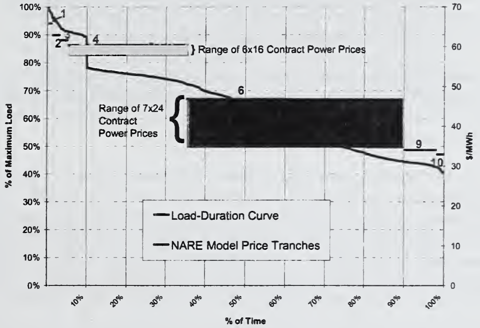
Table 1. NARE Model Electricity Price Tranches

Price Tranche	**% of Hours**	**Total Hours (31-day month)**
1	1	7.4
2	2	14.9
3	2	14.9
4	10	74.4
5	20	148.8
6	25	186.0
7	20	148.8
8	10	74.4
9	8	59.5
10	2	14.9
TOTAL	**100**	**744.0**

Based on Altos' long experience with electricity industry clients, it is reasonable and prudent to assume that contracted baseload (7x24) power will generally be available in

the market at price levels equivalent to the forecasted prices in tranches 6 through 8, and that contracted peak (6x16) power will generally be available in the market at price levels equivalent to the forecasted prices in tranches 4 or 5. Using these price tranches, we avoid the very high peak prices that occur during only 5 percent of hours each month (tranches 1 through 3).[10] The Contract Mix model allows the user to run multiple scenarios on power contract prices, effectively spanning the range of uncertainty about such pricing factors as the City's ESP's negotiating skills, the "tightness" of the market, etc.

Figure 3. Illustrative NARE Model Price Tranches and Power Product Pricing



For this analysis, we have used two sets of assumptions regarding the CCA's contracting outcomes. To model the "best," (i.e., lowest-cost) outcomes, we assume that the CCA (or its ESP) is able to purchase all of its contracted on-peak (6x16) power, each month, at our projected Tranche 5 price (the low end of the yellow box in Figure 3~~Figure 3~~), and all of its contracted baseload (7x24) power, each month, at our projected Tranche 8 price (the low end of the magenta box in Figure 3~~Figure 3~~). For a less optimistic view, we model purchases at the Tranche 4 price for peak power and the Tranche 7 price for baseload power.[11]

Within the Contract Mix Model, these pricing assumptions need only be applied to contracted power. CCA-owned power is assumed to be provided at cost. The levelized fixed costs of these CCA-owned resources are user input to the Contract Mix Model.

[10] At least a portion of the 5x8 power is likely to be purchased and/or sold in the 1-3 price tranches or at equivalently high administratively-set prices.

[11] We use the shorthand "5x8" and "4x7" to denote these two contracting assumptions, respectively.

Overall then, the Contract Mix Model allows the user to simulate the full range of power procurement and pricing options. By running multiple scenarios, the user can try to determine an "optimal" procurement strategy, or perhaps identify potential contracting pitfalls. The workings and use of the Contract Mix Model are explained in detail in Section 3.

2.1.5. Determining the CCA's Power Acquisitions

The Contract Mix Model allows the user to simulate the CCA's power acquisition on a month-by-month basis, taking into consideration the two kinds of products available -- baseload (7x24) and peak (6x16) – and any regulatory requirements on contracting behavior. The most important of these regulatory requirements is that the CCA will have to be fully contracted for power each month, i.e., the CCA cannot plan on using "spot" supplies unless its actual power demand is higher than forecasted.[12]

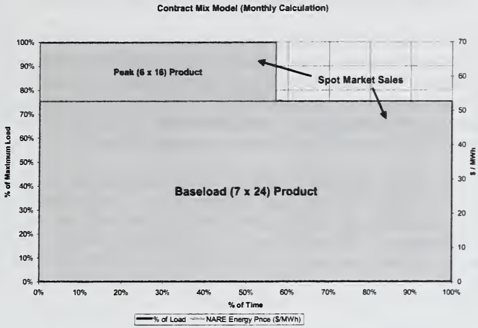
This regulatory prohibition against planned spot purchases, combined with the temporal constraints on peak (6x16) power, yield a power product pattern each month for the CCA that describes the amount of each type of product that is to be purchased. These purchases are illustrated in Figure 4~~Figure 4~~.

The Contract Mix Model automatically calculates the relative amounts of baseload (7x24) and peak (6x16) power purchases, which are reflected in the heights of the two gray-shaded rectangles. The CCA's load duration curve for the month is shown as the red line, using the left-hand percent-of-maximum-load scale. (For illustrative purposes, the forecasted market-clearing power price tranches, i.e., NARE Model output, are shown in the green line, using the right-hand $/MWh scale.) In the example above, the CCA buys about 77% of its maximum monthly load as baseload and the remainder as peak.

How does the Contract Mix Model calculate this mix of products? First, the 6x16 product is limited to only about 54 percent of the hours {6x16} / {7x24} = 53.9%), so this determines the horizontal width of the upper, darker gray bar representing the peak product. (In the cases that utilize the 5x8 "super-peak" product, this product is limited to about 24 percent of the hours (5x8 / 7x24 = 32.8%). See Figure 22~~Figure 22~~.) The width of the 7x24 product is, by its definition, the entire month. The regulatory requirement against spot purchases means that all of the area under the red load-duration curve must be covered by a contract, so the height of the light gray rectangle representing the baseload purchases must meet the red load duration curve where the right hand side of the peak rectangle meets the load duration curve.

[12] This regulatory requirement is discussed in more detail in Section 3 of this report.

Figure 4. Representation of CCA Power Purchasing



As seen in the figure, one inevitable result of the regulatory requirement for full contracting is that the CCA will have to sell excess power into the spot market virtually every hour in the month (assuming that the actual load exactly matches the forecasted load, for which the power contracts have been procured). The Contract Mix Model incorporates these sales, assumed to be at the forecasted (i.e., derived from the NARE Model) spot market price at each hour in the day, into the overall cost of power by subtracting the revenues from these sales from the expenditures for contracted power, to arrive at a net cost of power acquisition. The Contract Mix also allows the user to examine, for each case, the quantities and prices of these hour-by-hour spot sales

Altos notes that if this "no spot purchase" requirement is applied to all LSEs in California, there could be significant selling pressure in most hours of the year. If there is are more sellers than buyers (i.e., actual demand equal to or lower than forecasted in more places than it is higher than forecast), there "excess" power would have to be sold outside of California. Moreover, this situation could have potentially strong influences on the market prices for power in California. Simply put, if everyone is "long" power because of the regulatory requirements, most of the spot sales by California LSE could be at lower-than-expected prices. (In the modeling we have done for CCSF, we have assumed that the spot sales are made to some buyer in the WECC at the forecasted prices.)

The Contract Mix Model is general enough to represent either power product as coming from a 3[rd]-party contractor of from CCA-owned generation. The only difference might

be the cost of the power, but the determination of the relative shares of baseload and peak power each month is independent of the identity of the power supplier.

2.1.6. Electricity Market Scenarios Selected for Study by CCSF

The Departments specified a number of electricity market supply/demand scenario cases to be analyzed for this project. Altos utilized a version of its North American Regional Electricity (NARE) Model to forecast electricity prices and transmission flows in the Western Energy Coordinating Council (WECC)[13] market in these scenarios. The forecasted power prices from this model are an important input into the projections of prices that a CCSF CCA would have to pay for power in the marketplace.

For these scenarios, Altos used its "base case" input assumptions for the NARE model, modified only by the specific instructions from the SFPUC. On the demand side, three sets of SFPUC scenarios varied the amount of electricity load to be served by a CCSF CCA. On the supply side, four sets of scenarios varied the California regulatory requirement for renewable generation and the identity of the developer of this renewable generation. The 12 scenarios specified by the Departments are laid out as Base Case through Scenario 11 in the matrix in Table 2~~Table 2~~.

The first row of demand scenarios envisions the City's CCA electricity load growing at the same overall rate as the total power demand within the entire PG&E service territory, with no opt-out by CCSF customers. These scenarios, therefore, analyze the largest CCSF CCA (in terms of electricity demand) that might be achieved. The second row of demand scenarios envisions a much smaller CCA; while overall CCSF load grows at the PG&E growth rate, a significant portion of the load -- 50% of CCSF medium/large commercial and industrial demand, 10% of residential demand, and 20% of small commercial demand -- "opts out" of the CCA program in 2007 (and moves to service from PG&E or perhaps to Direct Access service). In the third row of scenarios – the "No Growth" cases -- CCSF electricity load served by the CCA is assumed to grow at the PG&E rate through the year 2013, and then it remains constant at 2013 level throughout the rest of the forecast horizon (through 2035). These last cases represent the effects of large-scale energy efficiency programs within CCSF, as well as Demand Response Programs and facilitation of Distributed Generation.

The first two columns of supply scenarios assume that merchant (i.e., "for profit") entities build the renewable energy generation facilities that might be required by CPUC's Renewable Portfolio Standards (RPS), as well as any new gas-fired generation that might be needed throughout the WECC. The Renewable Portfolio Standards are assumed for this analysis to apply to all electricity Load Serving Entities (utilities and CCAs) in California. One possible standard would require 20 percent of electricity to be supplied by renewables by 2010; the other standard would require 40 percent of electricity to be supplied by renewables by 2017. The third column of scenarios assumes that the CCSF

[13] The WECC is comprised of the states of Washington, Oregon, California, Arizona, New Mexico, Nevada, Utah, Colorado, Wyoming, Montana, and Idaho, the Canadian provinces of British Columbia, Alberta, and Saskatchewan, and portions of northwestern Mexico.

CCA would build its own renewable generation (for 6x16 power) and any new gas-fired generation (for 7x24 power) it needed. The fourth column of scenarios assumed that the CCSF CCA would build all of its renewable generation but only 50% of its needed gas-fired generation. In the cases where the CCA builds its own generation, these resources are assumed to come on line in 2009.

Altos ran its NARE Model to reflect all 12 of these cases, and each NARE Model run produces a complete set of forecasted power prices throughout the WECC for all months in the forecast horizon (2006-2035). These 12 cases form a set of scenarios over which the CCA v. PG&E cost comparison is performed. Additional analyses are conducted in sets of 12, as other assumptions and scenarios are introduced within the Contract Mix Model.

Table 2. Electricity Market Scenario Matrix As of March 2005

	Electricity Market Scenarios Specified by CCSF				**Additional Scenarios**
SUPPLY **DEMAND**	20% RPS by 2010; 100% merchant renewables and new gas-fired	40% RPS by 2017; 100% merchant renewables and new gas-fired	20% RPS by 2010; CCSF builds all its own renewables & all its new gas-fired beginning in 2010	40% RPS by 2017; CCSF builds all its own renewables and builds 50% of new gas-fired beginning in 2010	40% RPS by 2017; CCSF builds only renewables for peak power
Base: No CCSF opt-out; Medium PG&E growth rate	Base Case	Scenario 03	Scenario 06	Scenario 09	Scenario 12
Medium PG&E growth rate, but 50% of CCSF Med./Large Commercial & Industrial opt out in 2007	Scenario 01	Scenario 04	Scenario 07	Scenario 10	Scenario 13
Zero Growth in CCSF Load after 2013	Scenario 02	Scenario 05	Scenario 08	Scenario 11	Scenario 14

2.1.7. Additional Contract Mix Model Sensitivity Cases

For each of these twelve cases, Altos ran the Contract Mix Model to examine the CCA v. PG&E cost comparison; the result is a set of twelve Contract Mix Model outputs. However, during the course of this assignment, it became clear that some of the important market and regulatory uncertainties needed to be examined, through additional runs of the Contract Mix Model. Therefore, we ran additional sets of 12 cases to examine:

- Two alternative load profiles (see Section 2.3.5.1)
- Two alternative power contracting scenarios: one specifying the most optimistic (i.e., lowest-priced) contracting by CCSF's ESP, and one specifying less optimistic (i.e., higher-priced) contracting

This set of four scenarios results in a total of 48 Contract Mix Model runs.

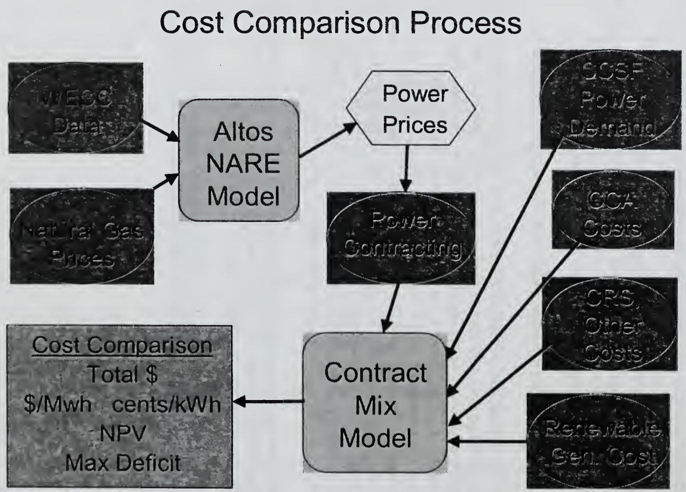
Based on some preliminary results that showed that CCA-owned natural gas-fired baseload (7x24) power could not compete in the market,[14] Altos and the Departments developed another set of power supply scenarios to study. In these scenarios, numbers 12, 13, and 14 in Table 2~~Table 2~~, the CCA is assumed to build only it's required peak (6x16) resources, assumed to be a "shaped" wind resource, and not build any baseload (7x24) resources. In these cases, the CCA is assumed to purchase baseload (7x24) power in the marketplace. For these CCA peak-build-only scenarios, we ran the Contract Mix Model, using the WECC power prices from the 40% RPS case, for the three CCA demand scenarios, the two alternative load profiles, and the two alternative contracting scenarios, for a total of 12 scenarios (3 demand x 2 load profile x 2 contracting).

In all then, the important insights and recommendations of our analysis are supported by a grand total of 60 Contract Mix Model runs (48 + 12), supported by the 12 overall supply/demand scenarios specified by the SFPUC staff.

The overall analysis methodology, including the use of the two computer simulation models and the relationship between user inputs and model outputs, is shown in Figure 5~~Figure 5~~.

[14] This result is discussed in more detail below.

Figure 5. CCA v. PG&E Cost Comparison Analysis



2.2. CCA v. PG&E Cost Comparison Results

For evaluating the cost comparison, the Contract Mix Model includes several metrics and graphics that illustrate various aspects of the cost comparison. These metrics and graphics are created by the Contract Mix Model for every scenario analyzed.

- Total Cost (Undiscounted Constant Dollars). This metric compares the two options' total cost over the 30-year forecast horizon, in undiscounted constant 2004 dollars.

- Year-by-year comparison chart. This chart compares the year-by-year total cost comparison for the two options, in constant 2004 dollars. This year-by-year comparison can also display the average cost of power, in both $/MWh and cents/kWh. This chart also includes the main components of the CCA's annual costs: power procurement, CRS, billing & administration, etc.

- Savings Chart. This chart shows the forecasted year-by-year and cumulative cost difference between the CCA option and the PG&E option.

- Net Present Value (NPV). This metric calculates the net present value of the year-by-year cost differences. A positive NPV indicates a long-term cost advantage for the CCA option, while a negative NPV indicates a long-term cost advantage for the PG&E option.

- Cumulative Loss. This statistic measures, on both a discounted and un-discounted basis, the largest cumulative deficit incurred in the CCA option, relative to the PG&E option.

2.2.1. Overall Results

The 60 Contract Mix Model runs provide some very clear insights into the basic question of the CCA v. PG&E cost comparison:

- The CCA could be an economically better option for CCSF in the long run, or it could be extremely unattractive financially.

- The key variable we identified as most critical to the long-term financial viability of the CCA option is the power contracting assumption.

- In every case, the CCA option is more expensive in the early years (2006 ~ 2010), and potentially less expensive in the later years.

- The maximum deficit incurred by the CCA (defined as the excess of costs over the PG&E option) reaches about $106 million in the "best" case, and up to 1 to 2 billion dollars in the "worst" cases.

The general result described above is manifested in these various metrics. The Total Cost comparison and the Savings Chart show that either option could be better, depending on the assumptions. The NPV could be positive or negative, again depending on the assumptions. The Cumulative Loss, however, is always negative. The CCA option always has a higher projected cost than the PG&E option in the early years -- at least in 2006 and 2007, and often longer – so this Cumulative Loss must be endured in all scenarios studied. In the cases that show the CCA is the better option, the CCA option eventually exhibits lower costs than the PG&E option, and these year-on-year savings reduce the early-year cumulative loss; after a number of years the loss disappears and positive benefits accrue in the long term. In the cases that show the CCA is not the better option, this cumulative loss grows every year and never turns around, since there are generally never any years in which the CCA option is lower-cost than the PG&E option.

In the following sections, we will describe selected cases from the 60 Contract Model Mix runs to illustrate these and other conclusions. In all of these cases (except as otherwise noted), the PG&E generation rates used as the benchmark for the cost comparison are the SFPUC forecasted rates shown in Figure 2~~Figure 2~~

2.2.2. Base Case Scenario

The Base Case scenario (from Table 2~~Table 2~~) is a good place to start to investigate the results of the analysis. This case posits that: the CCA's power load grows at the same rate as PG&E; the CPUC imposes a 20% Renewable Portfolio Standard for 2010 and beyond on all LSEs (CCAs as well as investor owned utilities); and the CCA does not build its own generation, but instead relies on purchases from the market. For analysis here, we have chosen the Contract Mix Model run that includes these parameters, as well as the assumption of using PG&E's Climate Zone Load Profile[15] and the assumption of the most optimistic contracting outcomes ("5x8").

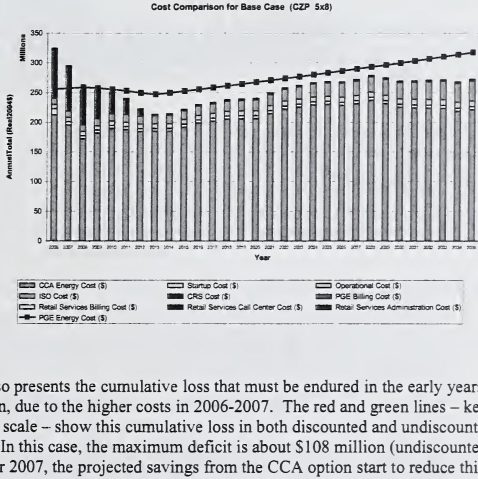
The important results of this Base Case are shown in Figure 6~~Figure 6~~ and Figure 7~~Figure 7~~. In Figure 6~~Figure 6~~, the vertical bars show the various cost components of the CCA's total cost of power; the most significant components are the power purchases (in gray) and the CRS (in red). In Figure 6 we see that the CCA option generally has higher costs than the PG&E option (represented by the blue line) in the early years of the forecast, and lower costs than PG&E in the later years.

The year-by-year savings are shown in Figure 7~~Figure 7~~. In this figure, the savings are shown in both undiscounted and discounted real 2004 dollars. The total savings, in real 2004 dollars, for the period 2006-2035 are shown in the boxes at the top: about $541 million undiscounted and about $189 million on a discounted basis. This positive $189 million figure is the Net Present Value of the savings that could be realized under the

[15] See Section 2.3.5.1 for a description of the Climate Zone Load Profile and the Dynamic Load Profile.

CCA option. The bars show the year-by-year savings. Bars shown above the horizontal axis (using the left-hand scale) indicate lower costs (i.e., annual savings) for the CCA option; bars below the horizontal axis indicate higher costs for the CCA v. PG&E. Here we see that the CCA option is more expensive than the PG&E option in 2006 and 2007, due entirely to a high level of CRS. The two options are fairly close in 2008-2010, but the CCA option is clearly preferable in all other years. One fundamental assumption in this analysis, discussed below, is that adequate renewable power is available in the wholesale market at competitive prices and does not carry any additional added costs that could potentially occur via the development of a renewable energy credit (REC) market.

Figure 6. Cost Comparison: Base Case (CZP 5x8)[16]



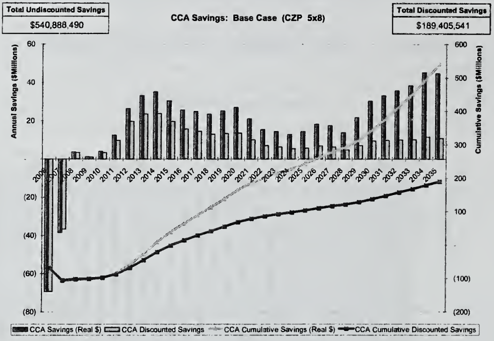
This figure also presents the cumulative loss that must be endured in the early years of CCA operation, due to the higher costs in 2006-2007. The red and green lines – keyed to the right-hand scale – show this cumulative loss in both discounted and undiscounted real 2004 dollars. In this case, the maximum deficit is about $108 million (undiscounted). However, after 2007, the projected savings from the CCA option start to reduce this cumulative deficit, and the cumulative savings turns positive, again using the right-hand scale, in about 2013 on both a discounted basis and undiscounted basis.

The savings chart for this case (show in Figure 7~~Figure 7~~) is particularly instructive in the economic analysis of the CCA option. In all cases, the savings chart has this basic shape. In each scenario investigated, the CCA incurs a cumulative deficit between 2006 and about 2013. A deficit is defined as meaning that CCA customers will pay higher bills

[16] For discussions of the CZP (Climate Zone Profile) load profile see section 2.3.5.

under the CCA option than they would if they stayed with PG&E service – assuming all CCA costs are recovered from CCA customers. In the favorable cases for the CCA, the deficit balance is reduced to zero after about 2013, and the benefits grow positive thereafter. In the unfavorable cases for the CCA, this deficit continues to grow and never turns around (see, for example, Figure 9~~Figure 9~~ below).

Figure 7. Savings Chart: Base Case (CZP 5x8)



These two figures illustrate some of the overall conclusions of the study.

- The CRS is basically the sole driver of the high costs for the CCA in the early years, and of the large cumulative deficit that would have to be endured in the cases that show long-term benefits of a CCA.

- The CCA operational and administrative costs and the ESP's operational costs and profits are only a very small part of the CCA's overall costs. Therefore, small improvements in costs are not going to make a big difference in the overall cost comparison; however during years when total CCA costs and PG&E generation costs are forecast to be close, e.g. 2008-2010, even small decreases in operational costs could result in some small discount off PG&E rates.

- The ISO costs are a small part of the equation, but their significance increase with time. In these cases, we have modeled these ISO costs as a per kWh cost, starting at about 2.2 cents/kWh in 2006 and increasing by about 2.5 % per year through 2035. The overall level of ISO costs grows as the charge grows and as total CCA load grows.

2.2.3. The Critical Impact of Power Contracting

The generally positive results of the CCA v. PG&E analysis in the Base Case discussed above are critically dependent on the assumption of the most optimistic (i.e., "5x8") contracting assumptions. The assumption is that the CCA or its ESP is able to contract for all of its power, month after month, at the low end of the range of prices that would generally be seen in the market for these contracted power products. Moving away from this assumption, to a less optimistic ("4x7") contracting scenario, changes the cost comparison dramatically negative for the CCA. In this scenario, baseload (7x24) purchases are made in the middle of the expected range of prices for that product, and peak (6x16) power purchases are made at the upper end of the expected range for that product.

The results for the Base Case with this less optimistic contracting assumption are shown in Figure 8~~Figure 8~~ and Figure 9~~Figure 9~~ below. This Contract Mix Model case is the same as the Base Case discussed above, but for the CCA power contracting assumption. The difference in results is stark.

In Figure 8~~Figure 8~~, we see that the CCA's costs are mostly higher than PG&E's costs throughout the forecast. In the years when the CCA's costs are lower (2012 through 2020) the savings are relatively small, but when the CCA costs are higher they are substantially higher. The boxes on top of Figure 9~~Figure 9~~ tell the story. The "loss" for the CCA option is now $485 million in total over the 30 years, or negative $245 million on a NPV basis. The cumulative loss grows in most years and the red and green remain negative throughout the forecast period.

These charts demonstrate the critical importance of the CCA's contracting outcomes, which are unknown at this time and which can only be known through real-time experience. If the CCA can achieve superior contracting outcomes – the 5x8 pricing – the CCA option can be better than the PG&E option. However, if the CCA cannot achieve superior contracting outcome every month for the 30-year period, it runs a significant financial risk, and the CCA customers would have been better off under service from PG&E.

Somewhere between the 100% 5x8 contracting and the 100% 4x7 contracting there are probably many contracting scenarios – a mix of 5x8 and 4x7 for the 360 months – that may yield a "break-even" point. In this study, we have not tried to find these points, but the SFPUC Staff, with the Contract Mix Model at their disposal, can find those points.

Figure 8. Base Case Cost Savings: (CZP 4x7)

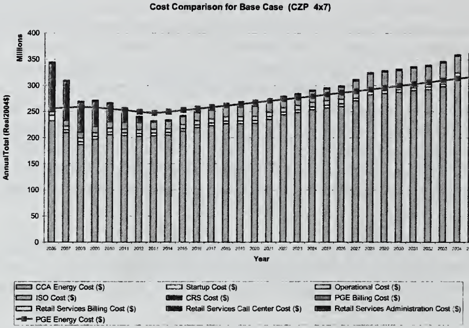
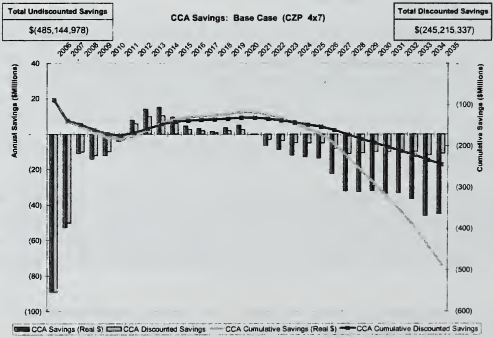


Figure 9. Savings Chart: Base Case (CZP 4x7)



Finding these points will give CCSF some idea of the potential contracting risks. For example, if achieving the "break-even" point requires 90% contracting at the 5x8 prices, that is a more risky proposition than if achieving the "break-even" point requires only e.g. 40% contracting at 5x8.

2.2.4. "Best Case" Scenario

Of the 60 cases examined by Altos, the "best case" scenario for the CCA option appears to be a Scenario 12 case in which the CCA is able to contract for power at very attractive prices. This case has the following important attributes:

- CCSF power demand growing at the same rate as PG&E's load;
- 40 percent RPS by 2017;
- No customer opt out;
- CCA builds only its peak (6x16) power resources, utilizing a "shaped" wind resource;
- The best possible CCA power contracting outcomes; and
- Dynamic Load Profile.

This case exhibits the largest difference in total cost for the CCA v. PG&E over the 30-year forecast horizon (undiscounted, constant dollars) -- $7.59 billion v. $8.23 billion for 30 years – an 8% difference. This appears to be the best that the CCA can expect to do, given this forecast of PG&E generation rates. This case also shows a positive NPV of about $218 million. However, in this scenario, the CCA would show a negative cumulative balance of approximately $130 million during the early years of the forecast. The financial outcomes of the potential "Best Case" scenario are presented in Figure 10~~Figure 10~~ and Figure 11~~Figure 11~~.

This "best case" scenario depends critically on the power contracting assumptions. This case, like the Base Case described above, relies on the CCA obtaining, for every month in the 30-year forecast horizon, the lowest reasonable prices for both 7x24 baseload power and for 6x16 peak power; these are the NARE-model forecasted tranche 8 price and tranche 5 price, respectively.[17] If the CCA is not able to achieve this kind of pricing, for example, contracting at the tranche 7 price for baseload power and the tranche 4 price for 6x16 power, the overall, undiscounted cost of the CCA option would be 0.7 percent higher than PG&E procurement (v. 7.8% less under better purchasing outcomes) and the NPV would turn negative, to -$80 million.

[17] In this case, the CCA only buys 6x16 from 2006 through 2008; beginning in 2009 the CCA owns its 6x16 power resources.

Figure 10. Cost Comparison for "Best Case"

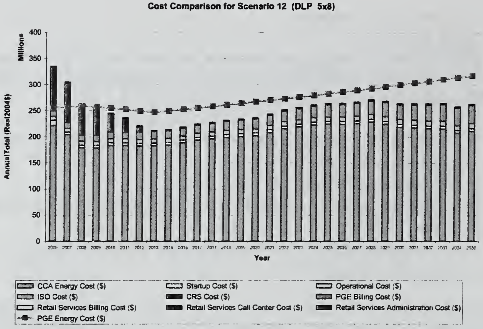
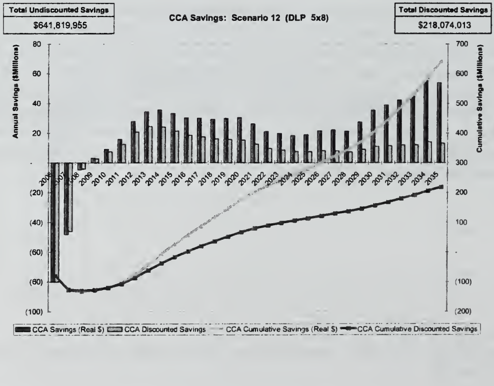


Figure 11. Savings Chart for "Best Case"



In total, there are only about 14 cases – out of the 62 examined – that show any degree of positive outcome for the CCA option. In 6 of these cases, the CCA builds only a "shaped wind" resource for peak (6x16) power; in 8 cases the CCA builds nothing and relies on the market purchases for 100% its power. The summary results of these 14 cases are shown in Table 3~~Table 3~~. In all of these cases it is assumed that the CCA achieves optimal contracting for all of the power it buys in the market.

Table 3. Potentially Positive Cases

Case Description	Cumulative Savings (Real $ millions)	Cumulative Discounted Savings ($ millions)	Low Point of Cumulative Savings (Real $ millions)	Low Point of Cumulative Savings, Discounted ($ millions)
	CCA Builds Only Shaped Wind 6x16			
Scenario 12 / DLP	641.8	218.1	-132.9	-130.2
Scenario 12 / CZP	595.3	202.0	-127.0	-124.5
Scenario 14 / DLP	471.8	160.7	-133.0	-130.3
Scenario 14 / CZP	436.4	148.3	-127.1	-124.6
Scenario 13 / DLP	140.9	-10.9	-133.2	-128.3
Scenario 13 / CZP	92.6	-29.1	-130.5	-125.5
	CCA Builds Nothing; 100% Market Purchases			
Base Case / CZP	540.9	189.4	-107.7	-105.9
Base Case / DLP	495.3	168.0	-111.5	-109.6
Scenario 3 / CZP	273.3	54.9	-135.8	-132.0
Scenario 3 / DLP	222.0	30.7	-144.6	-140.1
Scenario 2 / CZP	195.0	30.9	-135.6	-131.9
Scenario 5 / CZP	169.5	20.5	-135.7	-132.0
Scenario 2 / DLP	153.0	9.8	-144.3	-139.9
Scenario 5 / DLP	126.2	-1.1	-144.5	-140.0

Note: Scenario definitions are from Table 2~~Table 2~~. DLP = Dynamic Load Profile; CZP = Climate Zone Profile.

2.2.5. Insights from the "Worst Case" Scenario

This analysis has uncovered many potentially unattractive scenarios for a potential CCSF CCA. Indeed, 46 of the 60 cases examined showed disappointing results for the CCA option in all the metrics we identified. These cases are best described in terms of some of the major insights gained during this project.

- All of the cases in which the CCA builds new gas-fired baseload generation are unfavorable for the CCA.[18]
- All of the cases in which the CCA does not achieve optimal power contracting outcomes are not favorable for the CCA.
- Virtually all of the "Opt Out" cases show negative results for the CCA.
- The potentially positive Zero CCSF Load Growth cases (Scenarios 2, 5, and 14) show a lower level of benefit (i.e., savings v. PG&E) than the corresponding base case load growth cases (Base Case and Scenarios 3 and 12).

These insights merit some examination, as they reveal some important considerations in the CCA v. PG&E cost comparison.

2.2.5.1. CCA-Owned Baseload Power Cannot Compete in the Market

New CCA-owned gas-fired baseload power is not favorable for the CCA. Recall that the assumed technology for CCA-owned baseload resources is a new gas-fired, combined cycle unit. While this technology is the most efficient (i.e., lowest production cost) of the gas-fired options, in the WECC the price of baseload (7x24) power is generally set by resources with even lower production costs: hydro, nuclear, and coal-fired generation. In the off-peak hours (middle of the night, weekends) the low level of demand can generally be met solely by these lower-cost resources. The projected prices of these resources, reflected in the projected Tranche 7 or Tranche 8 price from the NARE Model outputs, is generally in the range of 3.5 to 4.1 cents/kWh. The projected cost of the assumed combined-cycle gas-fired generation is about 4.8 cents/kWh, so it is generally not competitive. We generally forecast an ongoing surplus of off-peak power in the WECC – the forecast of low-cost supplies from coal, nuclear, and hydro sources is higher than forecasted off-peak power demand – so the off-peak prices are projected to be low. This issue is also related to our forecast of gas price. If prices are higher, CCA-owned gas-fired baseload generation would be even more uneconomic. Given this dynamic for off-peak power, the CCA would be better off contracting in this market than trying to compete with its own gas-fired generation, and CCA investments in gas-fired baseload generation should probably be avoided.

[18] These scenarios analyzed the CCA building new gas-fired combined cycle generation for baseload (7x24) service. These scenarios did not address in any way the potential of the CCSF peaker (combustion turbine) project intended to provide intermediate and peaking power.

2.2.5.2. Optimal Contracting for Power is Crucial for CCA Success

The great importance of good power contracting outcomes cannot be overstated; it is described in some detail in Section 2.2.3 above. For baseload (7x24) power, the major difference between the best pricing and the less attractive contracting outcomes occurs during the summer months. During the winter, baseload power is generally forecasted to be available in the range of about 3.5 – about 4.1 cents/kWh (these are representative Tranche 8 and Tranche 7 prices, in real 2004 dollars). However, during the peak summer months, the increased level of demand often raises the forecasted Tranche 7 price to the range of about 6 cents/kWh (real 2004 dollars). For peak (6x16) power, the summer month differential between Tranche 4 and Tranche 5 is very small (both prices are generally in the range of about 5.8 – 6.2 cents/kWh. However, in the non-summer months, the lower demand reduces the Tranche 5 price to about 5.5 cents/kWh, while the Tranche 4 price remains around 6.2 cents/kWh. While these differences are only tenths of a cent per kWh, they are large enough to affect the outcome of the CCA v. PG&E cost comparison.

2.2.5.3. CCA Customer Opt Out Leads to Poor Financial Performance

Opt out generally leads to poor financial outcomes for the CCA, relative to the PG&E option. Recall, the "opt out" cases posit that 50% of the City's medium and large commercial/industrial load "opts out" of the CCA program, along with 20% of the small commercial load and 10% of the residential load. This significant loss of the large customers has the effect of reducing the average PG&E retail rate charged to the remaining CCA customers. The graph in Figure 2~~Figure 2~~ tells the story: The large customers that opt out have the highest PG&E generation rates (represented by the green, blue, and magenta lines).[19] When these high-rate customers opt out, the average PG&E generation rate for the remaining CCA customers is reduced, thus making the PG&E option more attractive. For example, in the Base Case for the year 2010, the average PG&E generation rate for CCA customers is 6.1 cents/kWh. In the equivalent "opt out" case, the average PG&E generation rate is 5.9 cents/kWh. In the opt out case, the CCA would have to achieve even lower prices in order to be competitive with the forecasted PG&E generation rates. Our analysis shows that, even with the best contracting outcomes, the CCA option generally cannot meet this lower cost of power. As seen in Table 3~~Table 3~~, there are only two potentially favorable opt-out cases (Scenario 13); they show small savings for the CCA on an undiscounted basis, but negative NPVs, indicating that the CCA is highly unfavorable in the early years, but more favorable in the middle and back end of the forecast horizon.

[19] The relative rates for the five customers classes are set by the CPUC, but are currently heavily influenced by California law. AB 1-X (enacted after the "energy crisis" of 2000-01) generally prevented the increased costs of power from being allocated to all residential customers, thereby increasing the rates to other customer classes, and yielding the relative rates for 2006 we see in Figure 2~~Figure 2~~. For the purposes of this analysis, Altos and SFPUC have assumed that future changes in generation rates are applied uniformly (on a percentage basis) across all five customer classes, so the relative positions of the lines in Figure 2~~Figure 2~~ remain the same through 2035.

2.2.5.4. CCSF Conservation Impacts

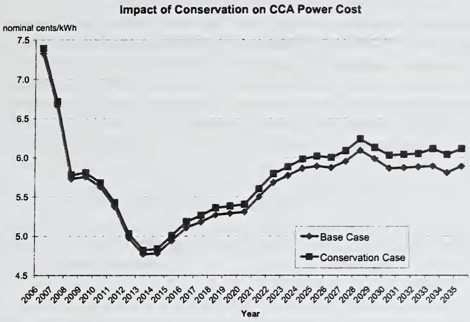
By design, we investigated several cases in which CCSF's CCA-served power demand remained flat after 2013, in order to examine the impacts of conservation. Table 3~~Table 3~~ shows that two of the cases that are potentially favorable for the CCA are variants of conservation scenarios (Scenario 2, 5, and 14), which assume zero load growth in CCSF power load after 2013. However, the potential benefits of the CCA option are somewhat lower than for the corresponding Base Case scenarios, in which CCSF power demand grows at the same rate as the rest of northern California.

If we look at the projected cost of power for the CCA in the Base Case and the corresponding conservation case, as shown in Figure 12~~Figure 12~~, the average cost of power in the conservation case is actually just a tad higher than in the base case. While this result appears counter-intuitive, a review of the economics behind it reveals some important insights. Clearly, the conservation case reflects a shift in the CCA's demand curve to the left (lower demand at the same price). However, the NARE Model results tell us that the supply curve also shifts relative to the Base Case, also to the left (reflecting less supply at the same price). Depending on the relative slopes of the supply and demand curves, the new resulting equilibrium price could be higher than, lower than, or equal to the old equilibrium price (in the Base Case).

The NARE Model output tells us that there is a different schedule of generation capacity additions in the Base Case and the corresponding conservation case. Generators, seeing the reduced demand, build a little less new (i.e., highly efficient) capacity each year. Because of this, some of the less efficient generators are able to stay in the market a bit longer. The slight price rise in the conservation case is the result of the market relying a little bit less on new, efficient, low-cost generation and relying a little bit more on older, more-costly generation. This difference in the generation mix, and especially in the marginal supplier that is setting the market-clearing price, is reflected in Figure 12~~Figure 12~~. The important point for the Departments here is to realize that conservation efforts in the City, or indeed, anywhere in California or in the WECC, will affect both the demand for power and the supply of power, and the resulting change in price cannot be known *a priori*. An integrated supply/demand tool like the NARE Model is crucial in determining whether the demand effects or the supply effects have the greater impact on price.

A very important assumption of the zero electricity growth case is that the achievement of zero electricity growth occurs by investments or by City ordinances or state law that occur outside the CCA costs and revenues. To the extent the CCA has to incorporate dollar investments from CCA revenues in reducing electricity consumption and electricity demand growth, there would be a corresponding reduction in CCA dollar savings.

Figure 12. Impact of Conservation on CCA Power Cost



2.2.6. Impacts of CCA-Owned Resources v. Market Purchases

The SCPUC originally specified two sets of scenarios in which the CCA would build its own generation resources: a "maximum build" situation in which the CCA builds 100 percent of both its renewable and gas-fired resources (scenarios 06, 07, and 08 in Table 2~~Table 2~~), and a "minimum build" situation in which the CCA builds 100 percent of its renewable resources and 50 percent of its gas fired resources (scenarios 09, 10, and 11 in Table 2~~Table 2~~). After discussion with SFPUC staff, we modeled "shaped" wind power as the renewable generation type, and we modeled it as a peak power (i.e., 6x16) resource. We modeled the gas-fired resource as a combined-cycle unit suitable for baseload, off-peak power (i.e., 7x24). With the concurrence of the SFPUC staff, we did not model any coal, nuclear, or hydro resources, or (for this phase) a gas-fired combustion turbine that is suitable for peak power.

Our initial results showed that all of these cases (Scenarios 6 through 11) produced negative financial results for the CCA option. It is clear from the above discussion on the relative costs and prices of baseload power that any potential price advantage of the "shaped" wind resource was being dominated by the cost disadvantage of CCA-owned gas-fired baseload generation.

This insight prompted Altos to investigate three related cases not specified by the SFPUC staff: scenarios in which the CCA builds only shaped wind for its peaking resources, but relied on market purchases for its baseload (7x24) power. We examined three such cases, with the three CCA demand scenarios prescribed by the SFPUC staff. Not surprisingly, these three cases are the best cases we examined, with the caveat that these attractive cases depend strongly on the CCA getting the best possible prices for its contracted

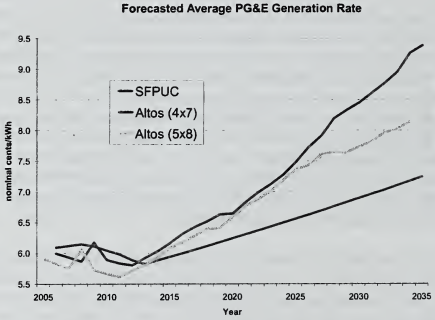
baseload power. If the CCA can only achieve average prices for this contracted power, the cost comparison turns negative.

Our analysis indicates that "shaped" wind resources can potentially compete in the peak (6x16) market. Based on discussions with experts in wind energy, we have modeled the "all-in" cost of CCA-owned "shaped" wind power at about 4.8 cents per kWh. This price can be competitive in the peak hours, when the price-setting source is a higher cost gas-fired source (often an older, inefficient boiler). For example, as noted above, the forecasted Tranche 4 and Tranche 5 prices – the prices at which contracted 6x16 power is generally available today – are generally above 5.5 cents per kWh. This is the price that a "shaped" wind product needs to beat in order to be competitive as peak (6x16) power.

2.2.7. Altos' alternative forecast of PG&E generation rates

At the request of SFPUC, Altos prepared two independent forecasts of the average PG&E generation rate for the years 2006-2035. Altos' forecasts are presented along with the SFPUC's forecast Figure 13~~Figure 13~~.

Figure 13. Altos & SFPUC Forecasted PG&E Generation Rate



For the SFPUC forecasts in the figure, we have used a load-weighted average of the forecasted generation rates shown in Figure 2~~Figure 2~~, using the CCSF CCA sectoral loads as weights. (A more precise weighted average would use the overall PG&E load, but using the CCSF loads provides a good proxy.)

Altos prepared its forecasts of the average PG&E generation rates using a combination of known and projected generation resources and their costs. The "known" resources include: PG&E-owned nuclear and hydro-generation; Qualifying Facilities (QFs) that are contracted to provide must-take power to PG&E: and the California Department of Water Resources (DWR) contracts that were allocated to PG&E by the CPUC. The projected costs and quantities of some of these "known" resources are available from a variety of sources, including PG&E, DWR, and the CPUC Office of Ratepayer Advocates. The analysis factored in the known expiration of DWR contracts, as well as known cost and quantity terms in the QF contracts. For each month in the forecast, if these "known" resources were not sufficient to meet PG&E's load, we assumed that PG&E would have to procure additional generation resources from the market. Altos used its NARE Model and the Contract Mix model to project the cost of these additional resources, in the same way that we projected the cost of resources that the CCA might procure. The two forecasts differ in the assumptions about the contracting outcomes for these additional resources: 5x8 reflects the lowest-cost contracting outcomes and 4x7 reflects higher-cost contracting outcomes. (These are the same contracting outcome assumptions used in examining the CCA's power purchases.)

The key underlying assumption here is that PG&E will be no different than any other buyer in the marketplace (including any CCA), facing an array of potential electricity suppliers in a competitive market. We assume that PG&E will purchase contract power under both baseload (7x24) and peak (6x16) contracts, and that PG&E would be under the same resource adequacy regulations as the CCAs. PG&E will not be at any special advantage or disadvantage relative to a CCA in terms of the prices at which it will be able to contract for power.[20] In short, PG&E will face the same competitive market for power as any CCA. PG&E has recently stated its intention to abide by the State of California Energy Action Plan (EAP) and contract such that 20% of its sales to its remaining bundled customers will meet the Renewable Portfolio Standard (RPS) requirements by 2010. We assume this commitment is met by the long-term contracting process required of the IOUs by the CPUC. Therefore this commitment is accounted for in our projection of PG&E's average generation rate. However this commitment is assumed to be met by PG&E purchases at or close to our forecast of wholesale market prices – not at the higher "market referent prices" established by the CPUC. To the extent that PG&E meets this RPS commitment at administratively-set prices, this forecast will tend to underestimate PG&E generation rates.

In addition, our forecasts of PG&E generation rates are directly related to our forecast of natural gas prices in northern California (see Figure 17~~Figure 17~~).

[20] We understand that PG&E has already made significant progress toward meeting the RPS standard. However, if PG&E simply meets the 20% RPS level and the CCA exceeds this 20% standard, the CCA generation rates could become uncompetitive due to the "market referent prices" being above the market-determined price.

Inspection of Figure 13~~Figure 13~~ yields some valuable insights:

- The three forecasts are reasonably close for the period 2006-2013, when the forecasts show generally declining PG&E generation rates in nominal terms. It appears that all three forecasts have fairly represented the impacts of the winding down of the "above-market" DWR contracts during this period.

- All three forecasts project increasing PG&E generation rates after about 2013. The difference is the rate of growth. The SFPUC projection grows by 1 percent per year from its low point in 2013; the Altos 4x7 projection grows by 2.1 percent per year from its nadir in 2012, while the 5x8 projection grows at about 1.6 percent per year.

- The difference between the Altos 5x8 forecast and the Altos 4x7 forecast appears to be relatively small, especially in comparison to forecasts of CCA generation costs using the two different contracting outcome assumptions. The difference is due to the fact that PG&E has access to significant power resources whose projected prices are not tied to these contracting outcome assumptions: nuclear, hydro, QFs. PG&E's will generally need to purchase a smaller share of it power from the competitive market than the CCSF CCA, so changes in assumptions about the price of this power will have a smaller overall impact on PG&E's average generation rate.

- The Altos forecasts are highly dependent on the assumptions about gas prices and PG&E contracting outcomes. Assuming a lower gas price and/or more favorable PG&E contracting outcomes could potentially yield a forecast that is more in line with SFPUC's forecast. However, Altos is not aware of the gas price or contracting assumptions embedded in the SFPUC forecast (if any), so direct comparison on these points is difficult.

Clearly, if one of the Altos forecasts turns out to be more in line with the future results than the SFPUC forecast, the economic attractiveness of the CCA option could potentially increase. Larger benefits could accrue in the later years of the forecast, but these benefits would be reduced somewhat in the NPV calculations. However, the CCA v. PG&E cost comparisons should be evaluated with great care to try to match assumptions on both sides. For example, assuming equivalent contracting outcomes for both parties (i.e., 5x8 or 4x7) is probably a better analytical method than assuming different outcomes. With the Contract Mix Model, the SFPUC Staff can investigate the CCA v. PG&E cost comparison using any forecast of PG&E generation rates.

2.2.8. "Best Case" with Altos Forecast of PG&E Generation Rates

To investigate the impact of a different PG&E generation rate, we ran the Contract Mix Model using the "Best Case" parameters for CCA purchases with the Altos 5x8 Forecast of PG&E generation rates (the green line in Figure 13~~Figure 13~~). Note that this PG&E generation rate forecast is below the SFPUC forecast in the early years, and above it in

the later years. These differences should lead to less favorable results for the CCA option in the early years (including a larger cumulative deficit), and more favorable results for the CCA option in the later years, all compared to using the SFPUC forecast for PG&E generation rates.

These insights are borne out in Figure 14~~Figure 14~~ and Figure 15~~Figure 15~~. The cost comparison chart shows less favorable results in the early years, when the Altos forecast of PG&E generation rates is below that of SFPUC, while the situation is reversed in the later years of the forecast horizon. The summary results are shown in the Savings Chart. Using the Altos forecast of the PG&E generation rate, the overall savings (undiscounted) are now about $623 million (v. about $269 million in Figure 11~~Figure 11~~), and the NPV is about $101 million (v. $54 million). However, the cumulative deficit is now about $240 million (v. about $130 million) and the cumulative deficit does not disappear until 2024 (v. about 2020 in Figure 11~~Figure 11~~).

This summary analysis shows both the great impact that the forecast of the PG&E generation rate has on the CCA v. PG&E cost comparison. It is the benchmark against which the CCA performance is measured. This analysis also demonstrates the power of the Contract Mix Model to examine the impacts of alternate assumptions about future uncertainties in the marketplace.

Figure 14. "Best Case" with Altos Forecast of PG&E Generation Rates

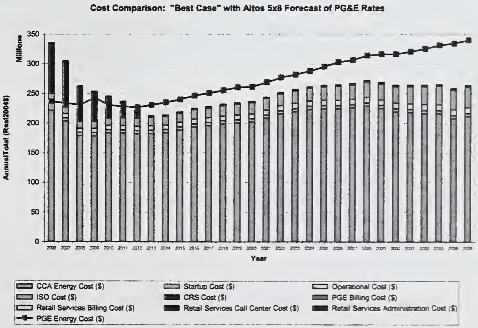
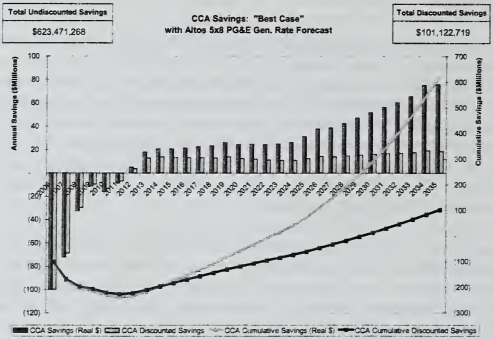


Figure 15. Savings Chart: "Best Case" with Altos Forecast of PG&E Gen. Rates



2.3. Other Factors Influencing the Cost Comparison Results

The overall cost comparison between PG&E procurement and CCA procurement is very complex, involving many market and regulatory factors and assumptions. We have developed a number of important insights into the manner and degree to which each of the following uncertain factors will influence the cost comparison, each of which deserves individual attention:

- Customer Responsibility Surcharge (CRS)
- CCA power supply contracting assumptions
- Natural gas prices
- Cost of renewable resources
- Regulatory issues and requirements
- CCSF electric load growth
- Renewable Portfolio Standard
- Other CCA costs

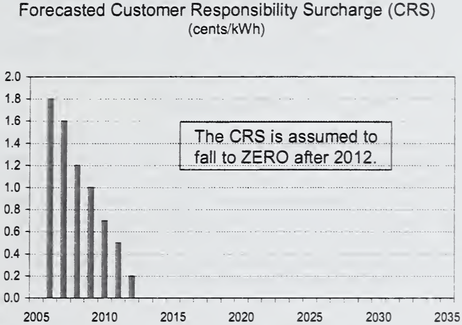
2.3.1. Customer Responsibility Surcharge (CRS)

The Customer Responsibility Charge (CRS) is the greatest near-term impediment to the potential economic success of a CCA.[21] The CRS is projected to start at 1.8 cents/kWh in 2006, and to decline to 0.7 cents/kWh in 2011 before dropping off in 2012. CCSF's

[21] A full description of the CRS is found in Chapter 9 (by the Departments).

current projection of the CRS is shown in Figure 16~~Figure 16~~. Figure 6~~Figure 6~~ and Figure 8~~Figure 8~~ clearly show that the CRS is major short-term negative influence on CCA costs, and one of the major determinants of the long-term attractiveness of the CCA option. In each chart, the total annual cost of the CRS is represented by the red bars. In the cases that show the CCA option as favorable in the long term, the CRS is the cause of the CCA option being more expensive than the PG&E option in the early years, and therefore it is the cause of the deficit that must be endured until the CCA savings can be achieved. However, even the elimination of the CRS would not solve all of the CCA's potential disadvantages; sub-optimal contracting outcomes by the CCA (i.e., 4x7 contracting) would still present negative financial results, even without the CRS.

Figure 16. Forecasted CRS



2.3.2. CCA power supply contracting assumptions

The assumptions about the CCA's power contracting – specifically, the purchase prices that the CCA can achieve in the marketplace – are a critical factor in the potential financial success of a CCA relative to continued service from PG&E. If the CCA can achieve the lowest feasible prices in the market for all of its contracted purchases every month – both off-peak (7x24) and on-peak (6x16) – the CCA can be the better option. If the CCA cannot achieve these most attractive prices, the CCA will not be the preferred option.

The situation is displayed in Figure 3~~Figure 3~~ which shows the ten NARE Model price forecast tranches overlaid on an illustrative load-duration curve. The figure shows peak

prices are forecasted for the highest demand periods of a month, and the lowest prices are forecasted for the lowest-demand periods of the month. Our experience with electricity industry clients that utilize the NARE Model indicates that a contract for 7x24 off-peak power can usually be obtained at prices within the range of price tranches 6 through 8 (shown in red in Figure 3~~Figure 3~~), and that a contract for 6x16 on-peak power can usually be obtained at prices within the range of prices tranches 4 to 5 (shown in blue in Figure 3~~Figure 3~~). Price tranches 1 through 3 represent only the highest-priced 5 percent of hours in a month, and so these prices are generally too high for a 6x16 product that is available about 56% of the hours in a month. Similarly, price tranches 9 and 10 represent only the lowest-priced 10 percent of hours in the month, and so these prices would generally be too low for a contract for 7x24 power, which is available every hour of the month.

As described above, the best cases for the CCA v. PG&E cost comparison are those in which the CCA is presumed to contract at the forecasted price 8 tranche for 7x24 power, and at the forecasted price 5 tranche for 6x16 power. These price tranches represent the low end of the range of reasonable prices to be expected for these contract power products. A less optimistic assumption about power contracting outcomes – the tranche 7 price for 7x24 power and the tranche 4 price for 6x16 power – shifts the outcome of the cost comparison so that the CCA option is not preferred.

This general conclusion about the importance of the CCA's contracting prowess is based on the simplifying assumption that the CCA contracts for power at the same price tranche for all 360 months in the forecast horizon (e.g., tranche 8 for all 7x24 power, in all 360 months). The best case contracting assumptions lead to a measurable positive result for the CCA. The Contract Mix Model has the flexibility to assume different contracting outcomes (i.e., price tranches for the products) every month, so it might be a worthwhile exercise for SFPUC staff to investigate the degree to which the CCA could withstand sub-optimal contracting for some months during the forecast horizon and still achieve a positive result. As a first step, for example, the SFPUC staff might assume optimal contracting for non-peak months (say, October through May), and sub-optimal contracting in peak months (June through September). Of course, many other contracting scenarios are possible, and the Contract Mix Model has been designed to examine this wide range of potential outcomes.

2.3.3. Natural gas prices

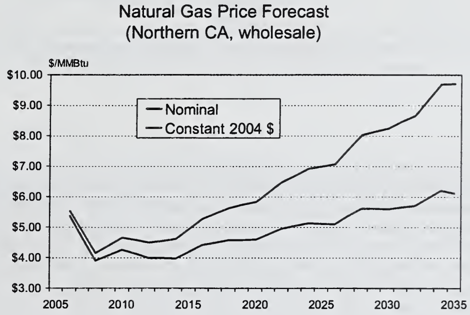
The price of natural gas in California is an important factor in the cost comparison, since gas is a major fuel for power generation in California and throughout the WECC. The price of gas tends to set the market-clearing price of electricity, especially in the on-peak hours. The forecasted gas price in Northern California that was used as an input to the NARE Model runs is presented in Figure 17~~Figure 17~~.

This projected dip in gas prices in the near term is the result of a number of factors: the recent high prices eliciting somewhat more North American supplies while suppressing demand somewhat, and increased availability of LNG imports to the U.S. later this

decade. Later in the next decade, however, increasing demand and the inevitable decline in domestic supplies will combine to raise prices.

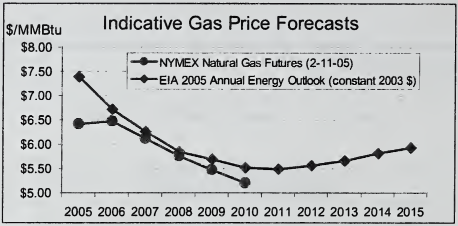
The general shape of this forecast is consistent with other indications price trends in the current forward markets for natural gas, as seen in the prices for gas futures contracts, as well as in other publicly available forecasts. Figure 18~~Figure 18~~ shows the current (mid-February) natural gas futures prices from the NYMEX as well as the Reference Case natural gas price forecast from the very recent 2005 Annual Energy Outlook from the Energy Information Administration.[22]

Figure 17. Natural Gas Price Forecast



[22] The AEO gas price forecast shown is the U.S. average gas acquisition price for electric generators, so it corresponds to the gas price forecast used in the NARE Model.

Figure 18. Indicative Natural Gas Price Forecasts



Of course, other gas price forecasts are possible, and each could have an impact on the CCA v. PG&E cost comparison. In addition, gas prices will tend to fluctuate around these annual average forecasts, reflecting short-term supply/demand conditions such as weather, economic activity, etc. Higher gas prices will cause higher electricity prices, which will affect the power acquisition prices that can be achieved by both the CCA and PG&E. Thus, an alternative gas price scenario will change both the projected PG&E generation component and the cost of CCA power. To assess the impact of an alternative gas price forecast, the user would first run the NARE Model with the new gas price forecast to get new power price forecasts, and then run the Contract Mix Model. In addition, the forecasted PG&E generation components should be adjusted to be consistent with the new gas prices. (Altos has no information on what gas price forecast, if any, was utilized in Navigant Consulting's forecast of PG&E generation rates.)

2.3.4. Cost of renewable resources

The cost of renewable resources, specifically "shaped" wind power, could be a critical variable in the overall cost comparison. In this analysis, we utilized a levelized cost of 4.2 cents/kWh for the wind power, and an additional 0.6 cents/kWh for the shaping services. The 4.2 cents/kWh figure represents the constant, long-term price that will recover the capital costs of a large-scale wind farm, assuming the current interest rate environment and the current capital costs per MW for wind turbines. This rate has also been confirmed as reasonable by another consultant in this project. The 0.6 cents/kWh figure for shaping services reflects shaping services currently available in the

marketplace today,[23] and this figure has also been confirmed as reasonable by the same consultant. In this analysis, we have assumed that these prices remain at these levels, in constant dollars, throughout the forecast horizon.

Of course, these costs and prices may change over time and change the analysis. New technology may reduce the capital costs of wind power (in real terms), and interest rates will continue to fluctuate. However, any reduction in the per unit cost of wind will, of course, improve the financial prospects for a CCA. The Contract Mix Model is designed to accept alternative assumptions for the levelized cost of wind and for the price of shaping service, and alternative cases should be run, to examine the potential impacts of, say, a 10 percent reduction in wind power construction costs.

2.3.5. Regulatory issues and requirements

As of this writing, the specific rules and regulations for CCA are still under discussion at the CPUC. Two of these details that are important to the CCA v. PG&E cost comparison are the choice of CCA load profile and the resource adequacy requirements.

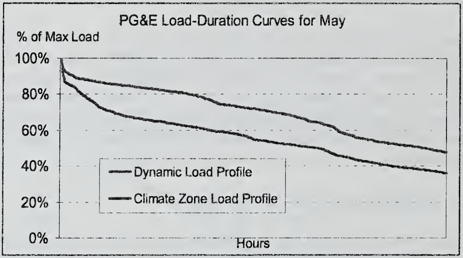
2.3.5.1. Load Profile

Although CCSF knows its overall monthly and annual electricity requirements (and can forecast these for the future), the hour-by-hour distribution of this demand – the precise "load-duration curve" – is not known. This load-duration curve is important because electricity is traded on an hourly basis, and the shape of the curve can determine the mix of electricity "products" the CCA might purchase. In the absence of a known load shape, the CCA must "shape" its total load into a load-duration curve. Current discussions at the CPUC have focused on two options for a "proxy" load profile for a CCSF CCA, both provided by PG&E: (1) the System Load Profile (which reflects the load shape of the entire PG&E service territory); and (2) the Climate Zone Profile (which reflects the load shape of PG&E territory along the Pacific Coast). The two different load profiles are shown in Figure 19~~Figure 19~~ for May 2003. (Each month will have a different set of curves, but the May curve is representative of the differences between the two load profiles.)

These two options vary with respect to how sharp the peak load is and how flat the middle of the load-duration curve is. The differences between these two load profiles can lead to different amounts of power purchased under baseload v. peaking contracts, and therefore they can affect the average cost of resources for the CCA. The Climate Zone Load Profile is more representative of the actual load in San Francisco, which can have a lower summer peak and a higher winter average load (relative to summer peak) than the PG&E system average load shape (represented by the Dynamic Load Profile).

[23] This 0.6 cents/kWh apparently includes the cost of any generating fuel the provider of shaping services might need to provide the service. The buyer of shaping service pays the flat fee, and there is no adder for fuel costs.

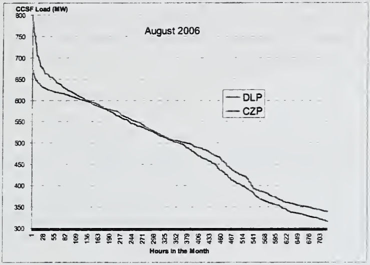
Figure 19. Alternative Load Profiles



Our analysis indicates that, especially for the favorable scenarios, using the Dynamic Load Profile produces better results for the CCA (see Table 3~~Table 3~~). Using the Dynamic Load Profile produces a slightly lower overall cost for CCA power acquisition, so the comparison to PG&E's generation rates looks better than using the Climate Zone Profile. On the surface, this outcome seems a bit counter-intuitive: should not the flatter CZP load profile reduce the need to purchase high-priced peak supplies, resulting in lower overall costs for the CCA and a better outcome relative to PG&E? We must look at the two load profiles on an absolute MW basis (not normalized to 100% as in Figure 19~~Figure 19~~ above.

The two load profiles (using the CCA's projected load) are shown for August 2006 in Figure 20~~Figure 20~~, to represent a typical high-demand month. The figure shows that the Dynamic Load Profile is below the Climate Zone Profile for much of the month – about 75% of the hours. Using the Dynamic Load Profile, then, the CCA would have to acquire less power during these hours than under the Climate Zone Profile. While the reverse is true for the other 25% of the hours in August, the overall effect for the month is that less power needs to be acquired using the Dynamic Load Profile, thus reducing the average cost of power acquisition.

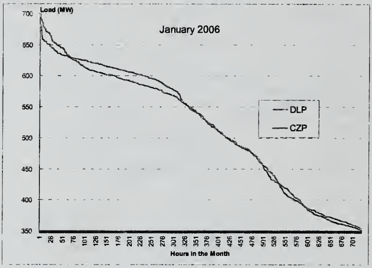
Figure 20. Load Profile Comparison: August 2006



This effect is less pronounced, but still evident, in the winter months. The two load profiles (using the CCA's projected load) are shown for January to represent a typical winter month. Here we see that, for the month, the total power acquired is roughly the same for the two load profiles. However, the total purchases are less during the winter, so the summer effect described above tends to dominate. Overall, due to the advantage of the Dynamic Load Profile for the summer months, the annual CCA v. PG&E results for the Dynamic Load Profile are more favorable for the CCA option than those for the Climate Zone Profile.

There is another effect at work here as well. The anticipated Resource Adequacy Requirements (see below) mandate that the CCA buy a full block of 6x16 peak power, when its load is only a portion of that block (i.e., the "triangle" under the load-duration curve shown in Figure 4~~Figure 4~~). The CCA is assumed to sell the excess power at hourly spot prices. When these spot prices are higher than the CCA's cost of this 6x16 contracted power, the CCA actually makes money on these sales, reducing its overall cost of the power it ultimately sells to its customers in CCSF. In the DLP cases, this 6x16 block purchased by the CCA is larger (i.e., more total MW), reflecting the higher peak load under the DLP. Since the CCSF demand is the same, the CCA sells more excess power and makes more money on these sales. Thus, the overall financial results using the Dynamic Load Profile are better than for the corresponding Climate Zone Profile.

Figure 21. Load Profile Comparison: January 2006



In the 46 cases with unfavorable results, other factors such sub-optimal contracting outcomes and high CCA generation costs are the major causes of the financial result; the choice of load profile is a minor consideration in these cases.

2.3.5.2. Resource Adequacy

The CPUC is currently in the midst of a proceeding to define resource adequacy requirements that it might impose on all LSEs, including CCAs. For this project, the Departments have directed Altos to make two reasonable assumptions regarding the types of requirements the CPUC might impose:

- A CCA must contract for a reserve margin for all hours during a month when the projected load is at least 90 percent of its maximum projected load that month; and

- A CCA must be fully contracted for its projected energy load every month, 30 days prior to the start of any month.

In practice, these requirements would have two potentially important effects on a CCA's power procurement practices. The first requirement mandates that the CCA contract for more power than it actually needs at its meters. However, this reserve margin is necessary for overall system operation, and it would be required whether or not the CCA is formed. It appears that this requirement merely shares the burden of the required reserve margin between the CCAs and the incumbent utilities. Nonetheless, this requirement adds costs to the CCA.

The second requirement basically mandates that the CCAs not incorporate spot purchases into their normal power procurement policies (during average weather conditions). Of course, if power demand during the month exceeds the contracted supply for any hour, the CCA would have to buy spot power to make up the shortfall. This requirement mandates that for each month, the CCA's power purchasing resembles Figure 25~~Figure 25~~, where the CCA would be expected (under average weather conditions) to make spot sales during much of the month, when contracted power supply exceeds the load.

2.3.6. Renewable Portfolio Standard

Inspection of Table 3~~Table 3~~ shows that under either of the Renewable Portfolio Standards (RPS) we analyzed, the CCA option could be more favorable than the PG&E option. Scenarios 12, 13, 14 and 5 all include a 40% RPS by 2017, while the Base Case and Scenario 2 have a 20% RPS by 2010. The table shows that, among the potentially favorable cases, the 40% RPS runs show higher savings for the CCA option v. the PG&E option. However, it should be noted that the scenarios we ran were not exhaustive. For example, we did not run the scenarios equivalent to 12, 13, and 14 (i.e., CCA builds only on-peak, "shaped" wind resources). However it is again crucial to state that the wholesale price impacts of the RPS standard are assumed to be neutral. That is, it is assumed that renewable power will be widely available at prices competitive with existing sources of power – coal, natural gas, and large-scale hydro. For example, if an investor-owned utility (IOU) contracts for 6x16 power from a renewable generator, this power will not strictly follow the IOU's load, but a portion of the power will have to be sold in the normal course of business as excess into the wholesale market. But if a market develops specifically for renewable energy credits that are bundled with the renewable power (due to meeting regulatory goals or market preferences) then wholesale renewable power purchases would be differentiated and would become more expensive, with resulting impacts on generation rates.

At the direction of the SFPUC, Altos further studied the question of wholesale renewable power purchases through a modification of the Contract Mix Model and running two additional scenario cases. We made three significant refinements to the Contract Mix Model:

- Addition of a third power product: a "5x8" "super-peak" product, assumed to be available 10 AM to 6 PM, Monday through Friday (the highest peak hours each week). This product is assumed to be a solar resource.

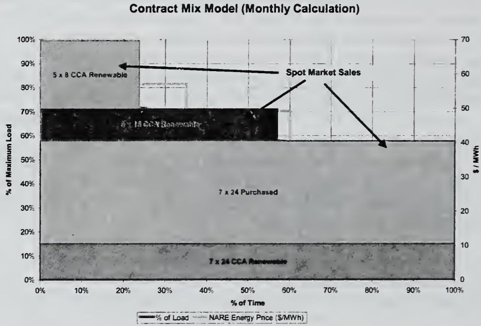
- Inclusion of an explicitly renewable block of 7x24 baseload power (in addition to the "standard" 7x24 baseload product). This new renewable block of power is assumed to be a biomass resource.

- Setting the prices of these two new renewable resources at exogenous (i.e., user-defined) values that are intended to represent the prospective "market referent prices" to be set by the CPUC.

With the addition of these two new resources, the illustrative "stacking" of potential power supplies for the CCA is as shown in Figure 22~~Figure 22~~

For purposes of this analysis, these two new renewable sources are assumed to be available in the market in 2009. Per the instruction of the SFPUC Staff, the price of the super-peak renewable resource was set to 11.5 cents per kWh, remaining constant in nominal dollars for the forecast horizon, and the price of the baseload renewable resource was set at 6.5 cents per kWh, remaining constant in real dollars for the forecast horizon. In addition, we ramped up the amount of baseload renewable power consumed by the CCA in order to meet the annual RPS target of 20% by 2010 and thereafter. All of the other parameters and assumptions remained the same as in the "Best Case" and we ran the Contract Mix Model for both the Dynamic Load Profile and the Climate Zone Profile.

Figure 22. CCA Power Products with Additional Renewable Resources



The Contract Mix Model results for these two cases, along with the results for the "Best Case" are shown in Table 4~~Table 4~~. The table shows the very large negative economic impact of the projected "market referent prices" for the required renewable resources. Simply, the "market referent prices" for these resources are well above the forecasted market price of power, so inclusion of these resources in the CCA's portfolio will necessarily raise its costs and tend to inhibit its financial performance v. the forecasted PG&E generation rates. The Renewables cases show higher costs for the CCA over the 30-year forecast horizon – about $1.8 to 1.9 billion more, undiscounted, as well as negative NPVs in the range of -$600 million to -$690 million. In addition, both Renewables cases show a large and ever-increasing "deficit" as compared to the PG&E

option (similar to that shown in Figure 9~~Figure 9~~). This large swing from positive results to negative results for the CCA option is one measure of the "price" of RPS standards. (It must be noted, however, that these CCA results are compared against the projected PG&E generation rates shown in Figure 2~~Figure 2~~. It is not clear to what extent, if any, that similar kinds of "market referent prices" are incorporated into these forecasts).

Table 4. "Best Case" v. Renewables Case

Case Description	Cumulative Savings (Real $ millions)	Cumulative Discounted Savings ($ millions)	Low Point of Cumulative Savings (Real $ millions)	Low Point of Cumulative Savings, Discounted ($ millions)
"Best Case" / DLP	641.8	218.1	-132.9	-130.2
"Best Case" / CZP	595.3	202.0	-127.0	-124.5
Renewables Case / DLP	-1,187.4	-608.6	-1,187.4	-608.6
Renewables Case / CZP	-1,339.4	-687.7	-1,339.4	-687.7

There are several factors that contribute to the reduction in potential savings in these "Renewables Cases:"

- The projected "market referent price" of the baseload renewable power – 6.5 cents per kWh – is significantly higher than the projected NARE Model Tranche 8 price for baseload power (at which the CCA is assumed to purchase its market-based 7x24 power). The projected Tranche 8 price is in the range of about 3.5 to 4.1 cents per kWh (see Section 2.2.5.1 above), so the renewable baseload power is up to 66 percent more expensive than the power it would replace in the CCA's portfolio.

- Similarly, the new "super-peak" renewable power, at 11.5 cents per kWh, is more expensive than the 4.8 cents per kWh "shaped wind" resource that it replaces at the peak.

- The CCA makes fewer profitable sales of excess 6x16 power. The new super-peak resource allows the CCA to purchase less power overall, since the three products can better fit the CCA's load profile than just the two products assumed in the "Best Case" (see Figure 22~~Figure 22~~ v. Figure 4~~Figure 4~~.) However, these excess sales are assumed to be made during peak hours, when market prices are projected to be higher than the cost of the "shaped wind" power. In the Renewables Cases, there are fewer of these profitable sales because the CCA buys less excess 6x16 power.

2.3.7. Other CCA Costs

Besides power procurement and the CRS, a CCA will have also incur other costs that it must recover from its customers. The most significant of these are: billing charges from PG&E; its own administrative and operational costs (most notably a call center); and charges assessed by the CA-ISO. As seen in Figure 6~~Figure 6~~, for example, these other CCA charges are a minuscule portion of the CCA's total costs each year. As such, the other factors discussed above will have a much greater impact on the CCA v. PG&E cost comparison over the long term. Nonetheless, the Contract Mix Model has been designed to accept alternative assumptions on all of these other CCA costs, to evaluate the potential impacts on the cost comparison.

2.4. Electricity Market Insights

Each of the twelve NARE Model cases that we ran for this project is an internally consistent forecast of electricity market prices and flows in the WECC, subject to the supply/demand input assumptions specified by the SFPUC. Analysis of these NARE Model outputs can provide a wealth of information into future conditions in the WECC. A number of important results and insights about the California electricity market are worth noting:

- **Customer "opt out" of the CCA program has virtually no impact on the market price of electricity in San Francisco or the WECC**. In the NARE model, and in the real world, the market clearing prices will be determined by the interaction of total supply and total demand. For any given supply scenario, the high opt-out cases have the same level of demand. The identity of the wholesale purchaser of power – the CCA or an investor-owned utility – does not affect the price, as long as the overall level of power demand is the same.

- **Electricity conservation in San Francisco has only a small impact on power prices in San Francisco and the WECC**. San Francisco's power market is not isolated; it is integrated within the overall WECC market that stretches from the Rocky Mountains to the Pacific Ocean, from Canada to Mexico. The power price in San Francisco is thus inextricably linked to this integrated, multi-state, multi-province grid. San Francisco's total load is about 5 percent of PG&E's load, and PG&E's load is only about 7 percent of the total load in the WECC. San Francisco's load is therefore less than 0.4 percent of the total WECC load. Thus, small savings in electricity demand in San Francisco will have a *de minimis* effect on the total overall electricity demand in the WECC. As long as a CCSF CCA buys any power from a merchant provider anywhere in the WECC, power prices in San Francisco will be affected much more by the overall supply/demand picture in the WECC than by any conservation efforts within CCSF.

- **The Renewable Portfolio Standards will affect power prices, and therefore affect the market in many ways.** In the NARE model, as in the real world, the market-clearing price of electricity is set, hour-by-hour, by the least-efficient

generator that is needed to balance the supply and demand on the system. The main economic impact of the renewable portfolio standards, as represented in the NARE model, is to reduce the need for generation from older, less efficient, fossil-fueled generation equipment in the WECC. During the off-peak hours, these fossil-fueled plants are generally not competitive, and the market-clearing power prices are generally set by the lowest-cost resources in the WECC: hydropower, nuclear, and coal-fired power. The presence of the renewable generation does not generally affect prices in these hours. However, during peak-hours, demand is generally forecasted to be high enough to require the operation of at least some of the higher-cost (and less efficient) generators to meet the demand. The basic effect of increasing the RPS from 20% to 40% would be that, during these on-peak hours, there are more renewable resources and fewer of the higher-cost fossil-fueled resources would be needed in the market. The first level effect, then, would be a reduced price in the on-peak hours, relative to the 20% RPS world.

However, in the NARE Model and in the real world, changes in prices can potentially change the entire forecast. As prices change, the market – both generators and consumers -- adjusts, and comes to a new equilibrium point. The lower prices in the peak hours can have numerous secondary effects, including:

- Increasing consumer demand, via price elasticities;
- Delaying investments in new, higher efficiency generation units; and
- Delaying retirements of older, less-efficient generation units.

These changes on the generation side will have price impacts in all hours, not just the peak hours that were seemingly the only hours affected by the increased RPS. A detailed examination of the many changes to the market caused by an increased RPS was beyond the scope of this study, but it appears that the RPS may actually tend to increase prices during at least some time periods, probably due to impacts on generation investments and retirements. Given its one-year license of the NARE Model and the MarketBuilder™ software, this might be an enlightening area for further study by SFPUC staff. Alternatively, as discussed above, regulatory requirements to meet RPS might lead to creation of a market for renewable energy credits (RECs), whether bundled with renewable power or sold separately. Over time, this market could differentiate renewable power sources and could create a market premium for renewable power purchases. In scenario 12 – where CCA makes large sales of "excess" wind-power in the wholesale market -- this market development could create further economic benefit for the CCA.

- **The Renewable Portfolio Standards will likely have to be met with both peaking and baseload resources.** In our analysis for CCSF, we have taken care to incorporate the RPS into the NARE Model as it forecasts the market clearing prices of electricity in the various scenarios. Our assumption is that if there are to be Supplemental Energy Payments (as defined by the CEC), these payments would be made <u>outside</u> the price system for electricity generation (however they

may be incorporated as higher electricity distribution rates). (The projected impacts of the RPS on the projections of market-clearing prices in the NARE Model are discussed above). In the CCA v. PG&E cost comparison, we identified favorable cases for the CCA option that assumed the CCSF CCA built its own renewable energy for its peaking (6x16) needs only. The Contract Mix Model calculates the share of this renewable energy in the CCA's overall portfolio. The cases we investigated showed that the share of this 6x16 renewable energy was only about 13 percent of total energy supplies in any given year. This result leads us to believe that LSEs cannot expect to meet the RPS on a percentage-of-consumption basis with peaking supplies only, and that they will likely have to include renewable resources in their baseload supplies. Alternatively, LSEs generating and selling renewable power could keep any RECs for themselves as an approach to meeting the RPS standard.

3. THE CONTRACT-MIX MODEL

3.1. Description of the Contract Mix Model

The Contract Mix model developed by Altos for CCSF is a computer spreadsheet/database tool that compares the projected average cost of power procured by a CCA v. the projected cost of the same amount of power purchased from PG&E. The Contract Mix model is an analytical tool that allows examination of the critical unknowns and uncertainties surrounding the economic feasibility of a CCA program (e.g., future PG&E generation rates, the degree of CCA customer opt-out, natural gas prices, capital costs for new renewable resources, etc.).

The basic cost comparison is relatively straightforward. The goal is to provide an "apples to apples" cost comparison of generation (or power procurement), not including the costs of transmission and distribution (which would be the same regardless of whether CCSF's non-municipal power load is procured by PG&E or the CCA). The cost comparison is depicted in Figure 1~~Figure 1~~.

On one side, the Contract Mix tool calculates the "generation" cost of power assuming that a CCA is not created and CCSF non-municipal customers continue to purchase power from PG&E. This calculation simply multiplies the forecasted purchases (in MWh) by an exogenous forecast of PG&E generation rates. For greater precision, both the electricity purchases and the projected PG&E generation rates can be segregated into the various sectors: residential, small commercial, medium commercial, large commercial, and industrial. The end result of this no-CCA option is an average $/MWh cost for CCSF's non-municipal load.

On the other side, the Contract Mix tool forecasts an equivalent cost of power assuming that a CCA is formed. However, this calculation is a bit more complex, because the CCA will have to incur costs other than simply the cost of power it acquires. First, the tool forecasts a cost of power, which can include both contracted power and spot purchases. To this, the tool adds the other costs that will be incurred by the CCA itself or directly by CCA customers, including:

- A Customer Responsibility Surcharge (CRS) that is determined by the CPUC;
- CCA start-up and operational costs;
- Billing charges paid to PG&E;
- CA-ISO charges; and
- ESP costs and profit

These additional charges must be added to the CCA side in order to represent all of the costs that will be incurred "upstream" of power transmission, so we can produce a meaningful comparison to PG&E's generation rates (which are also assumed to represent all costs upstream of transmission).

3.2. Use of the Contract Mix Model

The Contract Mix model is a highly interactive cost comparison tool. It can be used to evaluate a range of issues related to the formation of a CCA, including

- the overall desirability of creating a CCA;
- the market uncertainties that might affect the feasibility of a CCA;
- potential RFP approaches for a CCA to address RPS requirements; and
- alternative power contracting strategies for the CCA.

The basic steps in using the Contract Mix model are as follows:

1. Specify an electricity load forecast for the CCA
2. Specify a projected schedule of PG&E generation rates
3. Specify a NARE scenario (one of the 12 specified by CCSF, and used to calculate a price for the power purchases)
4. Specify the CCA's power purchases (contracted power and spot power)
5. Make assumptions regarding the cost of contracted power
6. Specify the CCA's non-power costs

The output of the Contract Mix model shows a comparison of average generation costs for the CCA option v. the non-CCA option, in both tabular and graphical format. The Contract Mix model can be run numerous times with varied input, to fully explore the issues listed above.

3.2.1. Inputs

There are numerous user-defined inputs to the Contract Mix model, each of which is described below. In general, these inputs can be varied by the user, to test the outcome of the CCA v. PG&E cost comparison to future uncertainties or sensitivities. The main inputs generally follow the steps outlined above, and are as follows:

- CCA Load Forecast
- Forecasted PG&E Generation Rate Components
- CCA Contracts and Spot Purchases/Sales
- CCA Non-Generation Costs

CCA Load Forecast

The forecast of CCA electricity demand is a function of four (4) main parameters, each of which is represented in the Contract Mix tool:

- Base load forecast;
- Load shape;
- Opt out percentage; and
- Demand growth.

Base Load Forecast. CCSF provided a base electricity load forecast for the customers it would serve, segregated into five (5) major customer classes:

- Residential
- Small Commercial
- Medium Commercial
- Large Commercial
- Large Commercial/Industrial

This load is exclusive of the City's municipal load, which is assumed to be served by Hetch Hetchy power, regardless of whether a CCA is formed.[24] This load forecast is for energy at the customers' meters, and so it must be "grossed up" for transmission and distribution losses (which the CCA must purchase). The Contract Mix model includes a feature to adjust for this loss percentage.

The base electricity forecast provided by CCSF reflects historical annual and monthly load data (by customer class), but not hourly data.[25] These annual or monthly aggregate data must be "shaped" to create a meaningful hourly load-duration curve for the CCSF CCA.

Load Shape. The contract mix model requires that the load forecast be in the form of a load-duration curve, which specifies the total CCA electricity demand for each of the 8760 hours per year (or for the hours during any month). To shape the data, the contract mix model can utilize either of two PG&E-provided load shapes: (1) its System Load Profile (which reflects the load shape of the entire PG&E service territory); and (2) the Climate Zone Profile (which reflects the load shape of PG&E territory along the Pacific Coast).[26] These two general load shapes are presented in Figure 19~~Figure 19~~. Using the chosen load shape, the projected total base case monthly load is spread out over all the hours of the month, in order to develop hourly electricity demand forecasts for the entire forecast horizon.

Opt Out. The CCA rules will allow any potential customer to "opt out" of the CCA program, and thereby continue to receive procurement service from PG&E. Any level of "opt out" will therefore reduce the amount of power that the CCA will have to buy every hour. The Contract Mix tool allows the user to forecast and specify any level of "opt-out" by customer class (on a percentage of base case load basis) as well as the timing of

[24] The CCA load also excludes in-city BART and Direct Access load that is supplied by others.

[25] Neither PG&E nor CCSF have access to hourly load data for the non-municipal load in the City. Virtually no residential or commercial customers have time-of-use meters, so these hourly load data simply do not exist.

[26] The Climate Zone approach tend to yield a load shape that is more representative of the actual load in San Francisco, which has a variable peak (sometimes winter peaking and sometimes summer peaking) and a higher winter average load (relative to summer peak) than the PG&E system average load shape.

this projected opt out (i.e., any level of opt out can be modeled as occurring at any time in the forecast horizon).

Demand Growth. Future growth in demand is computed with user-defined annual growth rates for total electricity demand, summer peak electricity demand, and winter peak electricity demand. Each of these three demand growth rates can be specified independently for each of the five customer classes listed above. The Contract Mix model then grows each hour's/tranche's demand accordingly, for the entire forecast horizon.

Forecasted PG&E Generation Rate Components.

The forecast of PG&E's generation rate components -- for residential, commercial, and industrial customers – provide the baseline for the CCA v. PG&E cost comparison. In the Contract Mix tool, these forecasts are multiplied by the projected load of CCSF non-municipal load, and an average cost of power from PG&E is calculated. The user is able to input whatever generation rate forecast is available, or to create one of his/her own.[27]

NARE Model Scenarios

As specified by the SFPUC, Altos prepared and ran fifteen alternative electricity supply/demand scenario cases using its North Atlantic Regional Electricity (NARE) Model, in order to evaluate the range of projected spot electricity prices in the WECC and in the northern California region. These 15 cases differed in terms of the forecasted level of power demand in the City, alternative assumptions about the regulate Renewable Portfolio Standard (RPS), and the amount of generation that is built by CCAs. The fifteen scenarios are presented in matrix form in Table 2~~Table 2~~.

Altos used a customized version of its NARE model to forecast market-clearing (i.e., "spot") power prices in the WECC market for ten time periods (or "tranches" in each month, for the years 2006-2035.[28] The NARE model developed for CCSF is a variant of Altos' standard WECC model; the modifications reflect a simplification of the geographical network structure, the disaggregation of the potential CCSF CCA load from the rest of the load served by PG&E, and an extension of the forecast horizon. All of these changes were implemented using the MarketBuilder™ software on which the NARE model runs.

The price forecasts from the NARE model are used in two ways in the "Contract Mix" model:

- To value the projected "real time" spot purchases and sales made by the CCA; and

[27] As one of the tasks in this project, Altos has developed for CCSF a forecast of PG&E's generation cost, utilizing results from NARE model runs and public data about existing contracts. This forecast is described in Section 2.2.7.

[28] A more detailed description of the MarketBuilder™ software and the NARE model is found in Section 4.

- To estimate the cost of fixed-price power contracts that the CCA is assumed to execute with third-party power producers/suppliers.

Together, the projected cost of contract power and the projected net cost of spot power (spot purchases less spot sales) comprise the projected power generation (or power supply) cost for the CCA.

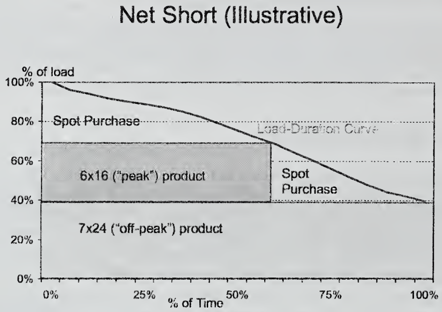
CCA Contracts and Spot Purchases/Sales.

The Contract Mix model includes a feature that allows evaluation of a CCA's alternative power contracting strategies.[29] Procurement of electric power supplies typically includes purchases of contract products (usually at fixed prices) as well as spot power (whose price may vary on an hourly basis). The model assumes that there will be two "contract" electricity products available. These two contract products – a 7x24 off-peak product and a 6x16 on-peak product – are generally available in the market today, on a month-to-month (or longer) basis. The 7x24 off-peak product is for baseload power: 24 hours a day, 7 days a week. The 6x16 on-peak product is available Monday through Saturday, 8AM through midnight. During a typical 31-day month, this 6x16 product would thus be available about 58 percent of the time. Spot power is available any hour of the day, at a market-determined price.

These three products – on-peak, off-peak, and spot – generate three main types of contracting policies, which we will term "net short," "net short/long," and "net long." Under a net short policy, the CCA's total contracted supply (a combination of peak and off-peak products) is less than total load every hour of the contracting period (month, year, etc.). Thus, in every hour, the CCA also has to purchase spot supplies (at the spot price) in order to fully supply its load. This situation is portrayed in Figure 23~~Figure 23~~ below. Under a net short/long policy, the CCA's total contracted load both exceeds and fall shorts of the total load at different times during the contract period. During the "short" hours the CCA would have to buy spot power, but during the "long" hours the CCA would have to sell its excess contracted power into the "grid" at a price assumed to be equal to the prevailing spot price. This situation is portrayed in Figure 24~~Figure 24~~. In a "net long" position, the CCA has contracted for its entire projected load in all hours, and would have to sell excess contracted power at all hours except the peak hour. This situation is portrayed in Figure 25~~Figure 25~~.

[29] Given the experience of 2000-2001, it is not expected that a CCSF CCA would rely exclusively on "spot market" power. Indeed, the evolving CPUC regulations for CCA will require some amount of forward contracting by CCAs.

Figure 23. Net Short Power Contracting



The Contract Mix model is designed to allow the user to specify any of these situations for any future month.[30] Specifically, the Contract Mix Model allows the user to specify the amount of capacity for each resource by specifying the "height" of each "brick" in the diagram, as a percentage of the maximum load each month.

Depending on the prices for the contract products, the amounts contracted, the spot prices, and the load shape, either type of contracting policy could be the lower-cost option. The Contract Mix tool allows the user to make assumptions about the future cost of contracted power, based on the spot prices projected using the NARE model.

[30] In actual practice, a CCA's contracting decisions may be affected by regulatory requirements for resource adequacy during the peak hours. (See next section of text as well as Chapter 9.)

Figure 24. Net Short/Long Contracting

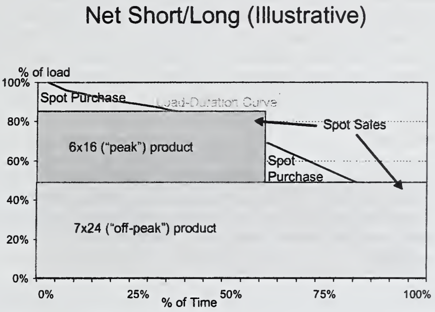
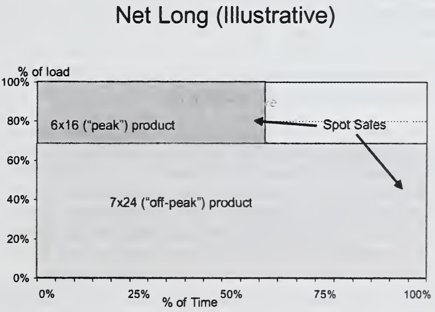


Figure 25. Net Long Contracting



CCA Owned Generation

In future years, the CCA may own, in whole or in part, generation resources that it has financed or built.[31] The Contract Mix model allows the user to specify an amount of CCA-owned resources in the CCA's portfolio of supplies, in addition to the contract products and spot power available in the marketplace. These CCA-owned resources may be baseload (i.e., 7x24) resources or peaking (6x16) resources. The assumed CCA-owned resources are a gas-fired combined-cycle for baseload and "shaped" wind for peaking. The Contract Mix model assumes that these CCA-owned resources are priced "at cost," specified outside the Contract Mix Model.

Contracting Regulations

The Contract Mix model allows for the overlay of the presumed regulatory requirements for CCA contracting. According to Altos' and the SFPUC staff's understanding, CCAs will, by CPUC regulation, have to meet certain requirements both forward contracting and reserve margin to ensure resource adequacy.[32] The Contract Mix model accounts for both of these regulations.

The current understanding of the forward contracting requirement is that:

1. By September 30 of every year, every LSE must contract for capacity for at least 90% of its projected load for each month in the following peak summer season (i.e., the following May through September); and

2. all LSEs will have to be fully contracted for capacity and energy at least one month ahead of time to meet expected loads.

These regulatory scenarios leads naturally to questions about the development of separate markets for generation capacity and electric energy in California, and the potential linkages between these two markets. While some might suggest that the capacity market and the energy market will be entirely separate, distinct, and independent, Altos believes, to the contrary, that the markets for energy and capacity, as expressed in their prices, will be absolutely linked, and that they cannot be un-linked.

To understand this point, let us understand that an LSE would make capacity payments to a generator in, say, September 2006 to "lock in" generation if the LSE needed to call on it during May – September 2007. Then, if the LSE needs the power from that generator, the LSE would make an energy payment to the generator and the power would be generated and consumed. In this construction, the capacity payments would generally cover the generator's fixed costs, while the energy payments would typically cover fuel and other non-fuel operating costs (if any). The question arises, then, what will be the

[31] Several of the NARE cases specified by the SFPUC assume a certain amount of generation resources being built by CCAs.
[32] As of this writing, the Resource Adequacy requirements and the detailed protocols to demonstrate Resource Adequacy are still under consideration at the CPUC.

relationship among the capacity payment (made in September 2006), the energy payment (made in Summer 2007), and the prevailing price for spot energy (the "all in" price during Summer 2007)?

Altos believes that the sum of the capacity payment and the energy payment must equal the spot price (at any hour that the LSE calls for power from the generator): Capacity + Energy = Spot (C + E = S). No other solution is economically rational. Consider the LSE. Hour-by-hour, his supply alternatives are: purchase power from the generator he has under capacity contract or purchase from the spot market. The rational LSE will not, consistently and over the long-run, pay more to the contracted generator, in total (i.e., for capacity plus energy), than the power is worth in the spot market at any given hour. On the other hand, the rational generator cannot expect to receive, consistently and over the long-run, capacity and energy payments whose sum exceeds the market-determined value of power on an hourly basis. Both sides will expect to be "price takers" in the very large WECC market of generators and purchasers, and the price that both sides will calibrate to is the hourly "all in" or spot price.

This calibration to the spot price means that capacity payments and energy payments will have an inverse relationship. If capacity payments are high, the subsequent energy payments (made when the electricity is actually needed) will be low. If the capacity payments are low, the energy payment will be high. In every case, the energy payment will make up the difference between the capacity payment and the spot price at the time the energy is delivered.

This inter-relationship among capacity, energy, and spot prices is captured in the NARE Model and the Contract Mix Model. We represent the CCA purchasing power contracts at an "all in" price (i.e., the sum of capacity and energy). This "all in" price reflects the total cost to the CCA for this power. While in the "real world" these payments would be made at two different times (capacity in September and energy in the following summer), the total cost to the CCA is the important value, and that value is reflected in the "all in" price that we use.

The Contract Mix Model represents the reserve margin requirements by increasing the amount of power the CCA must have contracted for the peak demand periods, using the following input factors (found under Miscellaneous Inputs):

Resource Adequacy Reserve Cutoff: This factor indicates the hours for which the reserve adequacy requirements are in effect. The current understanding of prospective CPUC regulations on this issue is that the reserve adequacy requirements will be in effect during all hours when the projected load is expected to be at least 90 percent of maximum load (i.e., the 10 percent of hours with the highest load).

Resource Adequacy Reserve Margin: This factor determines how much extra power needs to be contracted for during these hours. The current understanding of prospective CPUC regulations on this issue is a 17 percent reserve margin.

Coincidence Factor: This factor reduces the necessary reserve margin, to account for non-coincident peak loads. The current simplifying assumption regarding prospective CPUC regulations on this issue is for a 2.5 percent factor.

Using the currently proposed values, for each of the top 90 percent of hours, the CCA would have contracted an amount of power equal to:

$$\text{Base Load} \times 1.17 \times (1-0.025)$$

or about 114.1 percent of the projected load.

Very similar assumptions about resource adequacy requirements are embedded in the NARE model for this project, so the projected prices from those model runs accurately reflect the impacts of these resource adequacy requirements.

These resource adequacy requirements, if enacted by the CPUC, would constrain a CCA's contracting program to a "net long" position in every month (see Figure 25 above) if purchasing standard 7x24 or 6x16 wholesale market products. Thus, unless the CCA customers' power demand unexpectedly exceed the forecasted demand (e.g., due to hotter-than-average summer weather), the CCA would be selling excess contracted power every month into the spot market, presumably at spot prices.

CCA Non-Generation Costs

A CCA will, by necessity, incur other costs besides the cost of the power it procures for its customers. Some of these costs simply come with the creation of a new entity, while other costs will be mandated by the CPUC. All of these costs are incorporated into the Contract Mix tool, in order to provide a meaningful cost comparison to PG&E service. The major categories of these costs are:

- Customer Responsibility Surcharge
- PG&E Billing Charge
- CCA Operational Costs, and
- ESP Operational Costs and Profit

CRS. The CPUC will mandate a Customer Responsibility Surcharge (in cents per kWh or dollars per MWh) that is intended to leave the PG&E's remaining customers indifferent to the migration of load to CCAs. (The CRS is discussed more fully in Chapter 9). The Contract Mix model allows the user to input a CRS for each year in the forecast horizon. At some point the CRS is expected to disappear, and the Contract Mix tool allows a "zero" entry here to reflect this.

PG&E Billing Cost. Under CPUC regulations, PG&E will be allowed to charge the CCA for billing services it provides, such as: the line item information on the bill; billing inquiries from the CCA; and remitting generation charge monies to either the CCA or directly to the ESP. These charges are expected to be on a dollars/customer basis,

however to the Contract mix tool is set up to include variations on this costing methodology, like dollars per year, dollars per customer, or dollars per MWh.

CCA Operational Costs. These costs are assumed to cover administration, a call center, etc. The specific cost assumptions used in the contract mix tool are explained in the Executive Summary. The Contract Mix tool is designed to handle one-time (i.e., start-up) costs as well as ongoing costs.

ESP Profit. CCSF will likely contract out the job of procuring power for the CCA to an Energy Service Provider, or ESP. The ESPs are, of course, profit-seeking enterprises that will charge for their services above their costs. The Contract Mix tool allows the user to input a known or forecasted level of operations costs for the ESP, as well as the profit for the ESP, which must be part of the overall cost comparison.[33]

3.2.2. Model Output and Results

For each run, the Contract Mix Model produces spreadsheet that contains a full set of outputs for that case. This output includes:

- a Cost Comparison Chart (e.g., Figure 6~~Figure 6~~);
- a Savings Chart (e.g., Figure 7~~Figure 7~~);
- a full set of 360 monthly load/price/purchase charts (e.g., Figure 4~~Figure 4~~); and
- all the data supporting these charts, including hourly power load, tranche-by-tranche electricity prices, and CRS and other CCA costs.

Where applicable, the charts allow the user to view the results in a number of units, including total dollars, cents per kWh, and dollars per MWh. The Contract Mix Model is also set up with a Case Consolidator, which can compare the financial results of multiple cases, allowing the operator to, for example, sort the cases by a particular performance metric, such as NPV.

[33] In contrast, PG&E and the other CPUC-regulated utilities do not currently make a profit on their energy procurement activities, i.e., they do not "mark up" the cost of energy they buy. They are allowed to cover their procurement costs, including personnel and overhead. PG&E's regulated profit margin is related to the use of its transmission and distribution infrastructure and to its owned generation facilities (which earn a return on rate base), not to the cost of the energy that is delivered.

4. Description of the North American Regional Electricity (NARE) Model

4.1. NARE Model Overview

Altos Management Partner's North American Regional Electric Model (NARE) is a nodal pricing model of the entire North American electric grid. It forecasts an internally consistent set of market clearing prices, energy flows, and fully vintaged new capacity and transmission additions at every node within the North American system. NARE is built in the economic modeling software system MarketBuilder™. The MarketBuilder™ approach strives to calculate forward prices and price differentials in the market on a regionally disaggregated basis. NARE contains four categories of input data: supply, demand, transmission, and fuel. Each of these four categories contains one or more data elements. Altos has developed a set of processes and accompanying tools that contain raw data from industry sources (for example, EIA, NERC, FERC) that is used to create the NARE data elements in the four categories. This section describes the details of NARE, focusing in great detail on the raw data gathering and subsequent data transformation from the raw data format into a format for input and use within NARE.

The regions of the NARE Model are shown in Figure 26~~Figure 26~~. These regions generally follow the NERC regions and sub-regions. For this project for CCSF, Altos utilized a version of the model that just covered the WECC, which generally includes the sub-regions west of the Rocky Mountains (including Canada and northern Mexico), since this western grid is generally "self-contained" and relatively independent from the rest of the continental grid.

4.1.1. Electric Market Representation Within NARE

Within each region of NARE, the electric market is represented identically. Figure 27~~Figure 27~~ provides a schematic representation of the detail that resides within each region defined in NARE. Within each region is a rich representation of the major drivers and determinants of the electricity market:

1. Demand
2. Supply
3. Transmission
4. Fuel

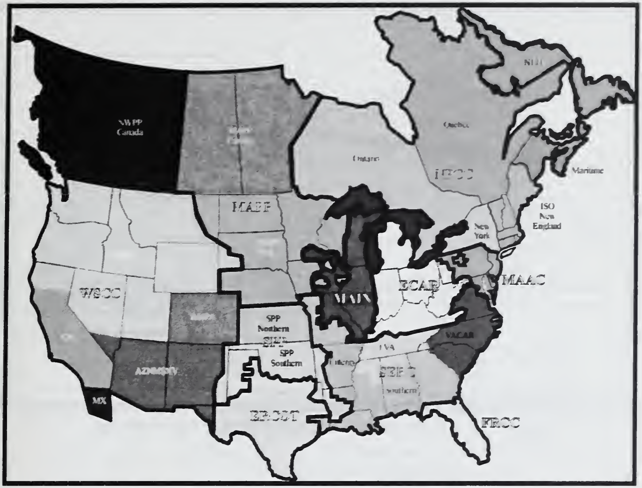


Figure 26. Geographical Scope of NARE Model

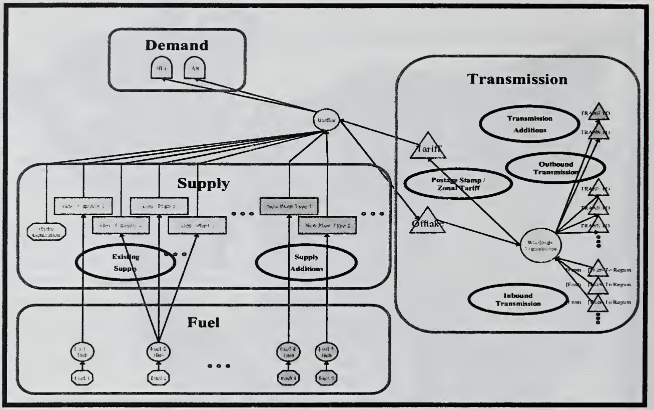


Figure 27. NARE Regional Electric Market Representation

4.1.2. NARE Data Categories – Overview

Four each of the four categories of data in NARE (see Figure 28~~Figure 28~~), the sections that follow describe the two step process of working with raw data that will become the NARE input. The first step is to identify, gather, and assemble the raw data. The second step is to transform the raw data into model inputs for NARE. Each data category goes through the same two steps of data identification, gathering, assembly and the transformation into model inputs.

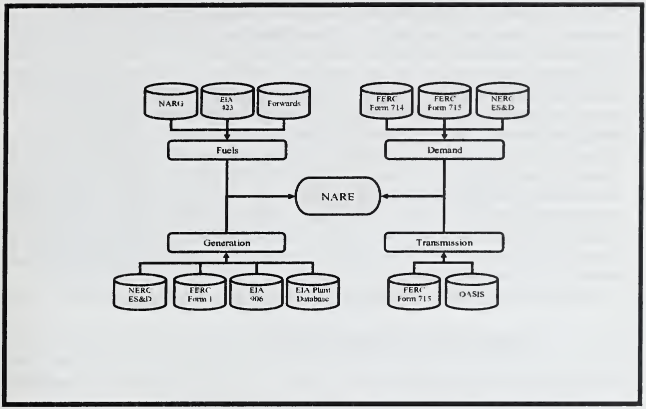


Figure 28. NARE Data Sources

4.2. Summary of the Modeling Approach

NARE is built in the economic modeling software system, MarketBuilder™. The MarketBuilder™ approach strives to calculate forward prices and price differentials in the market, on a regionally disaggregated basis. NARE is a nodal pricing model of the entire North American electric grid. It calculates market clearing prices and energy flows at every node within the North American system.

The first step in constructing our multiregional model of fuels, generation, transmission, and demand has been to regionalize the generation, transmission, and demand regions of the North American electric and fuel markets. Figure 1 provides a schematic representation of the overall regionalization used in the model. In building our model, we wanted to retain sufficient regional detail so that we can properly represent the capital stocks of generation capacity and fuel supply in each region as distinct from every other region. However, we do not want the model to become so large and unwieldy that it became un-runnable. The regionalization in Figure 26~~Figure 26~~, based in significant measure on the NERC regions and sub-regions, provided an effective compromise between the objectives of extensive regional detail at one end of the spectrum and workability and usability at the other.[34]

[34] The map in Figure 26~~Figure 26~~ is conceptual and not meant to be comprehensive.

The various nodes in Figure 27~~Figure 27~~ are defined as locations at which there are aggregates of generation, aggregates of load, aggregates of inbound transmission, and/or aggregates of outbound transmission. These nodes themselves can therefore be thought of as regional market entities that compete against each other as well as complement each other within the market. We think of generators in each of the nodes as competing for load not only at the node in which their generator is physically located but also in contiguous nodes in which their generator might have a competitive advantage over incumbents in that node. In the Altos NARE model, just as in the real world, there is "rivalry" among the nodes in a region to meet the markets resident within each node. It is this rivalry that dictates which generators will run, which will not, which segments of the transmission system will be used, which will not, and where after all such rivalry plays out prices will ultimately be driven. In effect, MarketBuilder™ simulates the North American power system as an interconnected "war game" based on the principles of competitive economic equilibrium. There are no entitlements to anything; all power competes physically based on price with all other power to and from everywhere.

4.2.1. Representation of Electricity Supply

Having regionalized the North American market as in Figure 26~~Figure 26~~, the next task is to specify the nature of the existing generation mix region-by-region. To develop the necessary data, we have estimated the capacity and the forward cost to market for every one of the generation units in every one of the 106 regions in North America—utility-owned units and independently owned units alike. MarketBuilder™ represents in its input data base some 17,500 generating units in North America, every transmission corridor, and every point of use. The complete representation of historical, existing, embedded generation capacity is represented in MarketBuilder™ as a supply stack that exists as of the first time point in the model horizon. In addition, MarketBuilder™ represents all historical vintages of plants and their operation and/or retirement throughout the model horizon. (Operation and retirement are endogenous.) While representation of existing vintages of capacity is not particularly unique, MarketBuilder™ does it in great detail for North America as a whole. Furthermore, however, MarketBuilder™ tracks the competitiveness and economic viability of each and every vintage of capacity that presently exists and predicts when it will be retired.

4.2.2. Regional Representation of Demand and Load Shape

It is important to develop precise estimates of load magnitudes and load shapes in every region of North America so that you know the specific nature of load at every disparate location within the state. It is clear that we need to model load in sufficient detail to capture the attractive load times.

The MarketBuilder™ models begin with a detailed download of the hour-by-hour FERC Form 714 demand data for historical years. The FERC Form 714 reports hour-by-hour load by every reporting entity in the United States. We sort those loads from highest to lowest during each month to develop a continuous, complete monthly load duration

curves. These monthly load duration curves are historical and represent exactly the load shapes that have actually occurred in the market.

After deriving historical monthly load duration curves, it is necessary to project those monthly load duration curves forward in time for the next 20 years. To do so, we assume a growth rate for the entire annual collection of monthly load duration curves. In particular, we must grow not only the entire curve, but differentially grow each individual tranche of that curve. The NERC projections of load into the future gives the forward growth rate of "energy," which is the entire area under the curve, and it gives the forward growth rate of "peak" which is the highest tranche of the July, August, or September curve depending upon which region one is considering. The model utilizes the entire localized load duration curve and the growth rate forward in time for the next decade for each tranche of that load duration curve.

4.2.3. Representation of Electric Transmission

The NARE Model also incorporates electric transmission capacity, using first contingency transmission capabilities along the transmission corridors between the nodes or regions.

The source of these data is the annual FERC Form-715 Annual Transmission Filings, which contain capacity and line loss data for the transmission lines connecting each pair of substations. We have defined our regions by assigning each substation to a specific market region.

4.2.4. Fuel Costs

A key component to any NARE Model analysis is input fuel prices derived from our North American Regional Gas (NARG) Model. The NARG Model does for gas what the NARE Model does for electricity: it projects gas prices and flows across the entire North American network, incorporating data on gas supplies and costs, pipeline transmission capacities and costs, distribution company costs, end-use demand characteristics, inter-fuel substitution possibilities, gas storage, etc. For the NARE Model, the most significant output from the NARG Model is the set of regional gas prices in the gas demand nodes (gas demand includes that used for power generation), which are used by the NARE Model as fuel prices for gas-fired electricity generation within each NARE electricity supply region.

4.2.5. Solution Methodology

The MarketBuilder™ models use "high technology," i.e., state-of-the-art, quantitative economic science, to help us represent what is likely to happen as the future electricity market opens for competition. Economic science, which is becoming and will continue to become increasingly pertinent, is from our perspective represented in Figure 3. The Altos MarketBuilder™ model is unique in its ability to use the simple but deep

paradigm in Figure 3, which is the “rocket science” of the business.

The data discussed above comprise the supply and demand curves for electricity depicted in Figure 29~~Figure 29~~, and (not shown) the transmission grid that interconnects supply with demand. The model extends and extrapolates the simple supply-demand curve pair in the diagram to consider every region of North America and every future time point in sufficient detail so that the consequent projections of prices are sensible and complete. The NARE Model is a multiple time period, multiple region representation of the simple but profound concept in Figure 29~~Figure 29~~.

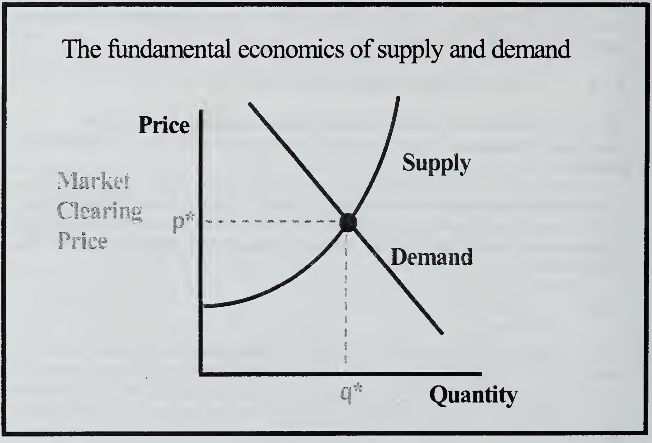


Figure 29. How the World Works

4.2.6. MarketBuilder™ Calculates Full Samuelsonian Spatial Equilibrium

By implementing the transmission component, thereby expanding the model in Figure 29~~Figure 29~~, we are able in our electricity market model to represent the true effects of inter- and intra-regional wheeling.

A simple example will illustrate the solution methodology and model output. Figure 30~~Figure 30~~ illustrates two contiguous regions, one a region (at the left) with excess generation capacity relative to demand and one (at the right) with tight capacity relative

to demand. Notice that the region with excess capacity at the left evidences a lower market-clearing price than the tight region in the absence of interconnecting transmission. As illustrated in the figure, if the incremental cost of transmission is smaller than the price differential that would be sustained in the market between the two regions if they were isolated (Balkanized), transmission will enter.

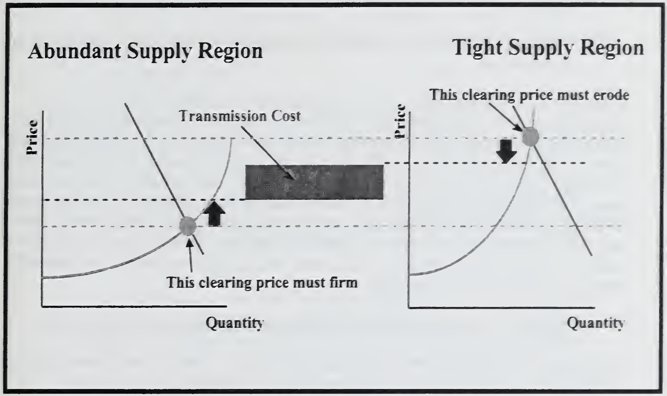


Figure 30. Transmission Dictates Prices and Differentials

The model solves for the market-clearing prices, generation and consumption quantities in all regions, and transmission quantities across all contiguous regions, for all time periods (e.g., ten time periods per month, 12 months a year). Our approach represents the simultaneity of transmission implicit in Figure 30~~Figure 30~~ and does not allow arbitrary assumptions.

The long run NARE Model also forecasts the amount of generation and transmission capacity that a competitive market would build. It builds plant and equipment of precisely the correct type at each and every node within the market until at every node the value of an additional MW of entry would be exactly zero. In effect, the long term NARE Model "builds" capacity, and it builds it to exactly the right amount.

5. Critical Analysis of the R.W. Beck Study Presented To SF LAFCO

The R.W. Beck study completed for the San Francisco LAFCO[35] presents its economic analysis of the potential benefits and costs of a CCA program in two sections:

- Section 3: Benefits and Risks of Community Aggregation in San Francisco; and
- Section 5: Preliminary Assessment of Feasibility of Community Aggregation in San Francisco.

In Section 3, R.W. Beck makes mostly non-quantitative statements about potential benefits and risks of a CCA program. In Section 5, the quantitative analysis that is presented suffers from being "preliminary" (in Beck's own words), over-simplified, and "static," i.e., not taking into account known and foreseeable changes to California's electricity markets. Moreover, R.W. Beck's analyses are now somewhat stale, due to the passage of time and the ongoing market and regulatory developments in California's electricity industry. Overall then, while Beck's economic analysis certainly identifies many of the important issues to be considered, it cannot, in its current form, meet the needs of CCSF for comprehensive, quantitative, and insightful analysis of the potential economic impacts of a CCA program.

5.1. <u>Section 3: Benefits and Risks of Community Aggregation in San Francisco</u>

In Section 3 of its report, R.W. Beck identifies a number of potential benefits and risks to CCSF that could result from the implementation of CCA, including:

<u>Potential Benefits</u>

- Local Control of Wholesale Power Supply Portfolio
- San Francisco Load Profile Relative to PG&E
- Opportunity for Greener Power Portfolio
- Protection from Wholesale Energy Price Volatility
- Real-Time Pricing for Peak Shaving -- Control Over City's Resource Requirements
- Ability to Control and Direct Public Benefit Dollars
- Opportunity to Develop Renewable Resources
- Provide Retail Market Access for Hetch Hetchy Hydro
- Provide Retail Access for Combustion Turbine Power Plants
- Opt Out Provides a Relatively Secure Rate Base
- Effect on San Francisco Financial Strength
- Achieve Some Objectives of Full Municipalization

[35] This report was delivered on August 6, 2003, and approved by resolution by the LAFCO on October 3, 2003.

Potential Risks (Cons)

- Exit Fees and Related Uncertainties
- Near-Term Opportunities for Hetch Hetchy Power Are Limited
- Minimizing Portfolio Risks Will Increase Power Procurement Costs

Unfortunately for CCSF, the R.W. Beck report does not provide quantified estimates of these potential benefits, or any probabilities or costs of the potentially risky outcomes.

We will discuss each of the potential benefits and risks identified by R.W. Beck in turn.

5.1.1. Potential Benefits

Local control of wholesale power supply portfolio. The adverse environmental impacts of the very old oil- and gas-fired generating units at the Hunters Point and Potrero power plants (in San Francisco's southeast sector) are well known. The R.W. Beck report indicates (page 3-1) that a CCSF CCA program could generate a dependable revenue stream that could be used to invest in power supply solutions that could lead to the closure of these plants. However, there are a number of potential problems and economic costs related to this statement, and the R.W. Beck report doesn't address any of them adequately:

- R.W. Beck assumes that the CCA program would generate revenues above its costs for power, administration, etc., and that these revenues would support the investments in the power supply solutions needed to close the two southeast plants. However, these extra revenues – recovered in rates charged to retail customers – do not appear to show up in R.W. Beck's economic analysis (pages 5-1 to 5-4), which seems to focus solely on the costs of power and related services (administration, customer service, etc.).[36] Of course, these extra revenues would have to be recovered from customers in the form of higher rates. R.W. Beck has not calculated how these higher rates (to cover ongoing power costs plus the new investments) would compare with PG&E's retail rates.

- R.W. Beck does not suggest the amount of capital investment that might be needed to provide these new supplies, nor does R.W. Beck identify a financing plan or an estimate of the total financing costs over time.

- Beck correctly states that the closure of the Hunters Point power plant, a stated goal of CCSF, PG&E, and the California Independent System Operator (CA-ISO), is subject to the exclusive approval of the CA-ISO. CCSF, PG&E, and others have begun to undertake projects that the CA-ISO acknowledges will allow them, once the projects are completed, to shut the plant. While the schedule for some of these projects may have slipped relative to their initial schedules, the R.W. Beck report does not indicate whether any CCSF investments in generation (funded from CCA revenues), would create the power supply conditions that

[36] A full discussion of the R.W. Beck economic analysis appears below in Section 5.2 of this chapter.

would allow the CA-ISO to shut the Hunters Point power plant any sooner than the current schedule. If the benefit of local control related to the shutdown of Hunters Point is one of speed, R.W. Beck has not shown that the CCA route would be any quicker than the status quo, and it has not shown how much time could be saved or how much CCA-funded investment would be required to accelerate the closure. In fact, in a press release on November 10, 2004, the SFPUC announced plans – focused on generation and transmission projects -- to close both plants by 2007.[37] Nothing in that announcement indicated that these plans were related to or dependent on the formation of a CCA in San Francisco.

- The shut-down of the Potrero power plant is more complicated. This power plant is owned by Mirant Corp., and its operations are currently supported by a Reliability-Must Run (RMR) contract with the CA-ISO (RMR status is reviewed annually). Basically, the CA-ISO has determined that the Potrero plant must remain on-line because there is not sufficient transmission capacity into the City to maintain reliability. Assuming that CCSF can acquire other resources (increased transmission capacity; other, cleaner in-City generation, conservation, etc.), the Potrero plant could lose its RMR status. At that point, the day-to-day and hour-to-hour operation of the Potrero plant would be based on economic dispatch considerations. While the plant would appear to be at a competitive disadvantage to other suppliers due to its advanced age and relatively inefficient generation equipment, and therefore might not be dispatched very often, CCSF does not appear to have the authority to summarily shut the plant absent a buyout of Mirant. The potential cost of this buyout does not appear in the R.W. Beck report. In its November 11, 2004, press release, the SFPUC indicated that the San Francisco City Attorney would be negotiating with Mirant for the closure of the Potrero power plant, and it remains to be seen how that might be accomplished, and at what cost to CCSF.

San Francisco Load Profile Relative to PG&E

R.W. Beck correctly notes that CCSF's total electricity load profile is less "peaked" than that of PG&E, and claims that this difference could contribute to lower power acquisition costs, on average, under a CCA program for CCSF. R.W. Beck analyzed four scenarios to determine to what degree this difference in load shape might contribute to cost savings (pages 3-1 to 3-5). R.W. Beck's conclusion is that the differences in load shape would not create meaningful cost differences between PG&E and a CCSF CCA. This conclusion is, in Altos' opinion, more a result of the analysis methodologies used by R.W. Beck than a function of the load data. As discussed below, the analyses used by R.W. Beck simply would not show a significant cost difference even with a wide variation in load profiles.

- Scenario 1: Purchases at Forecasted Average Prices. In this scenario, R.W. Beck assumes that both CCSF and PG&E would have to buy power at the same forecasted average prices. Beck concludes that, in this case, the difference in load

[37] Please see http://sfwater.org/detail.cfm/MC_ID/5/MSC_ID/74/MTO_ID/114/C_ID/2241

shape does not result in a benefit to CCSF. This conclusion seems reasonable, given the assumptions. This scenario posits both CCSF and PG&E buying power from the same hourly (i.e., "spot") market, at a set of exogenously-developed forecasted prices (that will presumably be set in the market by the overall levels of supply, demand, and congestion). In this case, there is a single market-clearing price in each hour for both entities, and all power each hour is transacted at that price, so differences in load shape do not matter.

While R.W. Beck's conclusion here seems reasonable (based on the assumptions), the analysis is incomplete.

- The "projected monthly average and peak prices" are not shown in either text or tabular format, and the source of this price forecast does not appear in the R.W. Beck report.

- The actual power cost comparison between PG&E and CCSF is not shown. While the report states that this scenario showed "no benefit" to CCSF, it would be better to see the actual numbers and the calculations, to determine if there was, perhaps, a cost to CCSF.

- Scenario 2: Purchases at 2002 CAISO Prices. This scenario is similar to Scenario 1; the difference is that both entities would now buy power at hourly CAISO ex-post prices, rather than at some forecasted prices. In other words, this scenario attempts to "back-cast" what would have happened if CCSF had had a CCA program in 2002, using the actual prices from 2002. Again, this scenario showed no benefit, for, Altos believes, the same reason as Scenario 1: with both entities buying at the same hourly prices, differences in load shapes do not affect the per MWh price paid.

  Like Scenario 1, the R.W. Beck analysis here is also incomplete.

  - This section of the report does not show the actual prices used in this scenario.

  - Once again, the actual power cost comparison between PG&E and CCSF is not shown. While the report states that this scenario showed "no benefit" to CCSF, it would be better to see the actual numbers and the calculations, to determine if there was, perhaps, a cost to CCSF.

- Scenario 3: Cost of New Resources. This scenario is not completely described by R.W. Beck in its report, but Altos assumes that it reflects the cost of power from new, gas-fired generation to meet the different load shapes of CCSF and PG&E. R.W. Beck notes that while CCSF would need fewer peak resources than PG&E (a cost savings), it would need more intermediate load resources relative to baseload resources (a cost disadvantage relative to PG&E), and therefore the net result would be little or no overall savings to CCSF.

Once again, the R.W. Beck analysis is incomplete, to the degree that Altos cannot determine if the analysis of this scenario is reasonable.

- R.W. Beck does not specify the type of gas-fired generation technology it assumed, nor does it specify whether different technologies would be used for different purposes (e.g., combined-cycle gas turbine for baseload, combustion turbine for peak load, etc.).
- R.W. Beck does not present the critical cost and operating assumptions (capital cost per installed MW, operating cost per MWh, heat rate, etc.).
- R.W. Beck does not present any of the cost calculations for this scenario, either in hardcopy or spreadsheet (electronic) format. There is no quantification of what constitutes "little or no benefit."

- Scenario 4: Purchases at 1999 CA-PX Prices. This scenario is similar to Scenarios 1 and 2; this scenario simply posits an alternative hourly price series at which both entities would buy power. In this case, R.W. Beck uses recorded prices from 1999. Again, this scenario showed no benefit, for, Altos believes, the same reason as Scenarios 1 and 2: with both entities buying at the same hourly prices, differences in load shapes do not affect the per MWh price paid.

In addition to these flaws, the R.W. Beck analysis does not appear to address a potentially important factor in determining the potential load profile of a CCSF CCA. It appears that R.W. Beck is using the entire power load for CCSF in its analysis. However, the current CCSF municipal load (for municipal buildings, MUNI, etc.) is supplied by the SFPUC's Hetch Hetchy power system, and this municipal load is assumed for purposes of this study (the PG&E v. CCA cost comparison study) not to be included in a CCA program. Therefore the appropriate load profile comparison would be the CCA's load shape, not simply the load profile of CCSF as a whole. R.W. Beck has not considered how this CCA-specific load profile compares to that of PG&E.

R.W. Beck concludes that, using their analysis methodologies, the difference in load shapes between CCSF and PG&E does not create meaningful cost differences (Page 3-5). Given this conclusion, Altos is perplexed as to why R.W. Beck then states that customer level load shapes may give a different result, and why R.W. Beck suggests that a "lack of availability of good data" for all four scenarios has somehow tainted their analysis. Given the incompleteness of the R.W. Beck analyses, Altos cannot even speculate as to why more precise data might yield a different result. Altos suggests that perhaps Beck's choice of methodology for calculating cost should be examined, and perhaps refined. Certainly, Altos' choice for methodology would be different, as shown in Sections 1 through 4 of this chapter.

Opportunity for Greener Power Portfolio

R.W. Beck correctly identifies that under a CCA program, CCSF may be able to provide power supplies utilizing a "greener" portfolio of generation sources than might be available via purchases from PG&E (page 3-5). However, the R.W. Beck report does not indicate whether these "greener" resources would be purchased from third-parties or developed by CCSF, and R.W. Beck not attempted to quantify this benefit (on an economic or environmental basis), or to provide a comparison of the capital and operating costs of power from "green" sources versus other sources. If the "greener" resources are more expensive to procure than alternative supplies, it would be good for CCSF to know the "dollars and cents" magnitude of this expected "green" premium.

Protection from Wholesale Energy Price Volatility

R.W. Beck identifies a number of generation portfolio, rate-setting, and operational actions that, according to R.W. Beck, could serve to insulate retail customers from wholesale power price volatility, presumably the kind of price volatility found in the California market during 2000-2001 (page 3-6). However, the R.W. Beck report does not attempt any quantification of the costs or benefits of any of these potential volatility-dampening actions. There is no discussion of the degree to which each or all of these actions would reduce price volatility. There is no discussion of what might constitute an "acceptable" level of price volatility, nor is there a discussion of the costs, risks, or potential other effects of the identified actions. Finally, R.W. Beck does not (and cannot) claim that these actions would have to be initiated by a CCA. For example, R.W. Beck suggests (#3) that a power supply portfolio with some fixed costs would have reduced the price volatility seen during 2000-2001, if the market structure in place at that time for the investor owned utilities had allowed such a portfolio. A future market structure that allows PG&E to enter into fixed-price power contracts would also achieve this goal of reducing price volatility to San Francisco customers.

Real-Time Pricing for Peak Shaving -- Control Over City's Resource Requirements

R.W. Beck identifies a number of operational and rate-setting changes related to Hetch Hetchy and the current City municipal load it serves (pages 3-6 to 3-7). However, Beck does not quantify any of these claimed benefits. Moreover, the operation of Hetch Hetchy and the service to the municipal load is currently planned as independent of the adoption of a CCA program by CCSF. If a CCA program is adopted, it appears that the municipal load will continue to be served from Hetch Hetchy, and the municipal load will not be part of the power load that the CCA program will be obligated to serve. The changes identified by R.W. Beck in this section could be implemented even without the adoption of a CCA program, so these benefits, if they are ever quantified, should not enter into the cost-benefit analysis of a CCA program.

Ability to Control and Direct Public Benefit Dollars

R.W. Beck assumes that under a CCA program, CCSF could be in a position to control and direct the public benefit dollars it would be required to collect (under state regulations). R.W. Beck estimates these funds at about $12 million per year (page 3-7). These funds could be used for demand side management, energy efficiency, renewable resources, and low-income assistance in the City, where these dollars could have the

greatest impact on the city's electricity customers and their retail rates. However, the R.W. Beck analysis falls short in that it does not attempt to quantify the potential benefits of these funds, in terms of either dollars or megawatts saved. A long-term demand reduction would cause a decrease in overall electricity costs to CCSF, and the net present value of that cost reduction could be estimated. Such an analysis would begin to put a value on this benefit of local control of public benefit dollars, but it is missing from the R.W. Beck report.

Opportunity to Develop Renewable Resources
In this section (pages 3-7 to 3-8), R.W. Beck claims that under a CCA program, San Francisco and its customers could form partnerships to develop renewable resources beyond that which is likely to occur under the status quo. However, R.W. Beck does not identify the source of the development funds for these resources, nor does R.W. Beck perform any analysis of the costs or benefits (economic or environmental) related to these additional renewable resources.

Provide Retail Market Access for Hetch Hetchy Hydro
R.W. Beck claims that when additional Hetch Hetchy power supplies become available due to expiration and/or renegotiation of contracts with the Modesto and Turlock irrigation districts, CCSF would be able to optimize Hetch Hetchy generation for the benefit of CCA customers (page 3-8). Once again, however, R.W. Beck fails to adequately quantify this potential benefit. R.W. Beck does not provide an estimate for when this Hetch Hetchy power might be available due to contract expiration or renegotiation,[38] nor does Beck try to estimate the amount of available power. Furthermore, R.W. Beck does not address the issue of how the Raker Act might affect the delivery of Hetch Hetchy power to non-municipal loads under a CCA program. Finally, Beck's claims about a "200%" increase in value are not substantiated: the report specifies neither baseline values nor any assumptions about the potential cost of other power purchases, so the claimed benefit or increase in value cannot be verified.

Provide Retail Access for Combustion Turbine Power Plants
R.W. Beck claims that, under a CCA program, the 4 combustion turbine power plants to be built in San Francisco could provide an annual benefit of up to $400,000 per year during the first 10 years, rising to $1.3 million per year thereafter. This naked claim is problematic. First, R.W. Beck does not cite any legal basis for the claim that a CCSF CCA program would be able to use these turbines if they are not scheduled by CDWR. Moreover, R.W. Beck provides none of the necessary assumptions or calculations supporting these figures, including: (1) the amount of power from these turbines to be utilized by the CCA; (2) the costs of producing this power, including the cost of fuel; (3) the cost of alternative power supplies; and (4) market price forecasts that would show that these power supplies are "in the market."

[38] Later in the report (page 3-10), Beck cites December 31, 2007, as the expiration date for the Modesto Irrigation District contract.

Opt Out Provides a Relatively Secure Rate Base
R.W. Beck claims that since no more than about ten (10) percent of San Francisco customers would opt out of a CCA program, this large customer base would provide benefits, in the form of competitive prices for power and for other services (pages 3-8 to 3-9). There are several problems with this claim. First, R.W. Beck provides no support for its estimate of 10 percent opt out rate. There are no references to other similar programs of any kind throughout the U.S. that might support this claim. Moreover, it is not absolutely clear whether this 10 percent figure refers to customer numbers or to customer load. In addition, Beck makes no attempt to quantify this claimed benefit, with no attempt made to calculate or estimate the difference in power purchase costs (per unit) for a CCA serving, say, only 70 percent of potential customers (or load) versus 90 percent.

Effect on San Francisco Financial Strength
R.W. Beck claims that, under a CCA program, CCSF could retain 5% to 8% of total revenues from power sales – about $11 million to $18 million per year -- and that this revenue stream would increase the City's financial strength (page 3-9). R.W. Beck claims that this additional revenue, even if spent on infrastructure or other municipal purposes, would somehow improve the City's debt rating and therefore reduce its cost of debt. This claim has several problems. First, R.W. Beck does not show the nexus between additional City revenues and an improvement in debt rating. R.W. Beck does not provide an estimate of what the rating improvement might be, and what the resulting decrease in annual debt costs might be. Furthermore, R.W. Beck assumes that the retail rates charged by the CCA would have to exceed the costs (power supplies plus administration plus customer service, etc.), in order to provide this 5% to 8% of extra revenue. This assumption appears to contradict R.W. Beck's assumption that a CCSF CCA program would establish rates on a "cash needs" basis. In addition, R.W. Beck does not show how this assumption of "extra" revenue meshes with their assumptions (see Page 3-1 of the R.W. Beck report) about "extra" revenues being used for investments in green and/or renewable resources, or in power supply solutions that would lead to the closure of the southeast power plants.

Achieve Some Objectives of Full Municipalization
R.W. Beck correctly claims that some of the potential benefits of full municipalization could be achieved under a CCA program, at potentially lower cost and lower risk (page 3-9). R.W. Beck correctly identifies generation-related costs as a major component of retail customers' bills, so an emphasis on potential savings in this component of the bill is certainly appropriate. R.W. Beck also correctly points out the high failure rate associated with municipalization and the potential costs, risks, and time delays associated with municipalization efforts. While R.W. Beck does not provide a quantitative estimate of the percentage share of the total potential benefits of full municipalization that could be achieved through a CCA program, their insights here appear to be directionally correct.

5.1.2. Potential Risks

Exit Fees and Related Uncertainties

R.W. Beck identifies the uncertainties surrounding CPUC-imposed exit fees and the outcome of the PG&E bankruptcy proceeding as major unknowns in the analysis of potential costs and benefits of a CCA program for CCSF. Since R.W. Beck completed its report (August 2003), the PG&E utility has emerged from bankruptcy, and the California Public Utilities Commission (CPUC) has held hearings on CCA issues, including the calculation methodology for the Customer Responsibility Surcharge (CRS).[39] On December 16, 2004, the CPUC issued its decision in Phase 1 of the CCA proceeding, which included a proposed 2.0 cents per kilowatt-hour CRS at least for the next 18 months. At this level, the CRS is an important factor in the overall cost comparison, and R.W. Beck is correct that the future level of CRS, as determined by the CPUC, will continue to be an important issue.

Near-Term Opportunities for Hetch Hetchy Power Are Limited

Despite citing the opportunities for using Hetch Hetchy power supplies as a potential benefit to a CCSF CCA program (page 3-8), R.W. Beck also identifies the significant limitations to this potential benefit (page 3-10). The true impacts of Hetch Hetchy probably lie somewhere in between. Because of their unique status, we have assumed for purposes of our analysis that the Hetch Hetchy power supplies probably should not enter into the comparison between potential CCA supply costs and PG&E's prospective retail generation rates. First, the Raker Act appears to limit the use of Hetch Hetchy power to municipal users, so this power would not be available to the residential, commercial and industrial customers of a CCA. Second, the current SFPUC assumption is that municipal load will lie entirely outside of the CCA, i.e., the CCA will not serve the municipal load. Thus, R.W. Beck is probably more correct in minimizing these un-quantified potential benefits of Hetch Hetchy power

Minimizing Portfolio Risks Will Increase Power Procurement Costs

R.W. Beck correctly points out that a CCSF CCA program might incur costs to hedge its exposure to fluctuating energy prices; these costs would be above and beyond the direct costs to acquire electricity and administer the program (Page 3-11). While R.W. Beck estimates that these risk mitigation measures might add about 5 percent to the direct cost of power, the report does not appear to provide any basis for this estimate, or the factors that are part of its calculation. Therefore, it is difficult to evaluate whether this estimate is reasonable. Furthermore, R.W. Beck claims that the future PG&E power portfolio is likely to be more hedged than a CCSF CCA portfolio. Once again, however, the report fails to describe how the PG&E resources it identifies will be more at risk to market prices, or how PG&E's ownership of gas transmission and storage puts them in a "strong" position to hedge against gas price risk.[40] Furthermore, this claim includes

[39] The CRS has generally replaced "exit fee" as term of art that describes the charge to be applied to all electricity customers, whether served by a CCA or an incumbent utility, to cover the costs of the so-called "non-economic" generation costs (e.g., the DWR bonds, some QF contracts, etc.).

[40] PG&E's power procurement department is wholly separate from PG&E's California Gas Transmission (CGT) unit, which operates the intrastate gas transmission and storage assets. According to CPUC

certain assumptions about PG&E's future power procurement practices and policies, namely that its portfolio of resources will look like the current portfolio. But the R.W. Beck report does not support this assumption, especially given the current regulatory uncertainty surrounding California's evolving power markets.

5.2. Section 5: Preliminary Feasibility Analysis of CCA

In Section 5 of its report, R.W. Beck presents a preliminary feasibility analysis of community aggregation in San Francisco that purports to show significant benefits to San Francisco's electricity customers (pages 5-1 to 5-4). R.W. Beck's "model" for this analysis compares the expected generation credit from PG&E (representing PG&E's projected cost of power, which would be deducted from the fully-bundled retail rates) with estimated resource costs for a CCSF CCA. R.W. Beck claims that for the period 2004-2014, a CCSF CCA program could acquire power at prices that would be lower than the generation credit from PG&E, thus creating savings for CCSF customers. This analysis purports to show an annual savings of $10 million to $35 million for 2004-2014.

However, the R.W. Beck analysis here and its input data are not well documented, and R.W. Beck makes a number of assumptions that are unsupported or questionable. Overall, this feasibility analysis is over-simplistic, it takes a static view of the market (assuming that the current state of affairs in the electricity market will not change over the next twenty years), and R.W. Beck itself acknowledges some of its shortcomings in the report. Each of these issues is addressed below:

- R.W. Beck assumes that the Generation Credit is equal to the current (capped) credit for Direct Access Load, as shown in PG&E's Rate Schedule E-EC. There are several problems with this assumption, and Beck acknowledges at least some of them:
    - The assumed Generation Credit was applicable to Direct Access customers, and that rate schedule has been superseded.
    - At the time of the report, there were no rules for determining a generation credit for CCAs, so Beck simply used the only similar kind of credit that was extant.
    - The detailed methodology for calculating a generation credit for CCAs will be determined in the current CPUC proceeding on CCAs. In its decision in Phase I of this case, the CPUC has adopted a CRS of 2.0 cents per kilowatt-hour for at least the next 18 months.
- R.W. Beck assumes a fixed mix of generation resources for PG&E, specifically with respect to its hydropower, nuclear, and Qualifying Facility (QF) resources. R.W. Beck apparently assumes that the percentage shares of these resources

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regulations, the power procurement department gets no preferential treatment – in services, rates, or anything else – relative to CGT's other customers (whether affiliated with PG&E or not). If the power procurement department wants to hedge against gas price volatility by using PG&E-owned gas storage, it will have to contract for storage service at standard "recourse" rates approved by the CPUC.

remains constant for the period 2004-2024, even as PG&E's total portfolio of resources grows with market demand. However, these resources are limited, and will likely not grow in the future. No new nuclear capacity is expected at Diablo Canyon (or anywhere else), nor are increases in hydropower capacity expected. Similarly, the amount of power available from the QF contracts is fixed by those contracts. R.W. Beck's analysis would be more credible if it assumed that the capacity of these resources is fixed, and assumed that new generation capacity would be gas-fired (a mix of combined-cycle and combustion turbine technologies) or renewable (wind and/or solar).

- R.W. Beck assumes that the costs of generation from hydropower and nuclear resources will increase with the inflation rate. The report does not appear to present what inflation rate is assumed. More importantly, R.W. Beck gives no support for this assumption. There is no analysis of whether these costs have risen at the inflation rate during recent history. Also there is no differentiation between capital costs and operations & maintenance costs, which are likely to increase at different rates.

- R.W. Beck assumes that the costs to PG&E from its DWR and QF contracts will be constant for the period 2004-2024 (or to the end of the contract). While this may be the case, R. W. Beck offers no factual support that all of the prices in these contracts will be constant throughout their remaining lives. The R.W. Beck analysis would be better served with extensive documentation on this point.

- R.W. Beck assumes that the Customer Responsibility Surcharge (CRS) is dropped in 2012. The current CPUC proceeding also assumes that the CRS will expire in 2012, but the value of CRS for CCA customers is still unknown, and it is not at all clear that it will be equivalent to the current CRS for Direct Access (which R.W. Beck appears to use). Furthermore, the R.W. Beck analysis do not appear to present the value of CRS that is assumed. While there is now an adopted initial CRS of 2.0 cents per kWh, this value will likely be adjusted by the CPUC during the forecast period.

- R.W. Beck assumes that all power purchases by a CCSF CCA will be at spot market prices. This is perhaps the most glaring problem with the analysis. The California "energy crisis" of 2000-2001 showed the tremendous price risks inherent in a "100% spot" strategy for gas purchases. We would expect that CCSF would learn from this experience and mitigate its price risks, and that its CCA program would have a diverse portfolio of resources, including both spot and contract purchases, with a mix of duration terms in its contracts (to the extent allowed by regulation). Indeed, apart from the strategic reasons a CCA program would likely develop a balanced portfolio, there are now regulatory requirements in process that will require a CCA to enter into contracts for power.

- For its spot electricity price forecast, R.W. Beck cites a California Energy Commission (CEC) forecast (made in December 2001) for the period 2002-2012.

The Beck report does not validate or even discuss the forecast methodology, nor does it explain how it arrives at its forecasts for the period 2013-2024, which apparently lies beyond the scope of the CEC forecast. Altos respectfully suggests that a more defensible forecast of regional/nodal electricity prices in California can be obtained through using a comprehensive supply/demand model, such as the North American Regional Electricity (NARE) model.[41]

- R.W. Beck appears to have included the total electricity load in CCSF (as presented in the December 2002 Electric Resource Plan prepared by SFPUC and SFE) in its analysis of potential savings. However, SFPUC staff acknowledge that the City's municipal load – up to about 200 MW – is assumed to remain outside of any CCA program. Thus, since the total load is overstated, the potential savings from a CCA program are also overstated in the R.W. Beck analysis.

- The R.W. Beck analysis appears ambivalent about how power supplied by Hetch Hetchy, new solar, new renewables, and the four Williams combustion turbines will factor into its analysis. R.W. Beck acknowledges that these resources have been omitted from its analysis. In the accompanying text, R.W. Beck claims that these resources will have a "positive impact on the cost, reliability, and potential savings generated by a CCA plan." However, R.W. Beck does not explain how these resources would affect a CCA plan. The facts surrounding these resources do not indicate how these resources would affect the market differently with a CCSF CCA versus without a CCSF CCA. For example, as discussed above, the Hetch Hetchy resources are reserved for municipal uses, outside the CCA program.

- R.W. Beck assumes additional costs for ISO transportation fees/scheduling and CCA program administrative fees of 8% and 3% of total direct power costs, respectively. However, R.W. Beck does not provide support for these cost estimates.

- The R.W. Beck analysis does not include any estimate for the cost of price risk mitigation strategies (hedging, etc.) or any cost recovery, profit, or risk premium for an energy service provider (ESP) that might be contracted by CCSF to run the CCA program. Addition of these very real costs to the analysis would certainly reduce any potential benefit.

- R.W. Beck claims that the potential benefits of a CCA program are in the range of $10-$35 million per year. However, a close inspection of R.W. Beck's Table 5-1 (page 5-3) shows that this statement applies only to the period 2004-2014. After this, the purported savings are less, and, beginning in 2019 the analysis shows a net negative benefit (i.e., CCSF would have been better off without a CCA

[41] As part of this engagement, CCSF has licensed the NARE and the MarketBuilder™ software on which it runs, for a one-year, renewable term.

program and staying as a bundled customer of PG&E). The R.W. Beck report should explain these later year effects.

- R.W. Beck claims that its estimate of potential benefits is "conservative." However, given all of the questions and uncertainties surrounding this analysis, it is difficult to assess whether the analysis is conservative or aggressive.

Following its Preliminary Feasibility Study, R.W. Beck presents a one-paragraph "Risk Assessment" of CCA, and concludes that the downside risk is low (page 5-4). R.W. Beck cites its observation that "power markets have returned" and the possibility that CCSF can use Hetch Hetchy and the combustion turbines as future power supply sources as pointing towards a low-risk situation. Clearly, these conclusory statements do not constitute a formal risk assessment in any real sense. Moreover, R.W. Beck's statement about the current state of the California electricity market is of little use; it will be important to be able to forecast what the California electricity market will look like when CCSF potentially implements a CCA program. By that time, the supply/demand situation may have changed, the regulatory environment may have changed, etc. Finally, R.W. Beck's statements about the Hetch Hetchy and combustion turbine resources are not terribly meaningful. As discussed above, the Hetch Hetchy resources are dedicated to the City's municipal load, which is assumed to remain <u>outside</u> any CCA program. The power from the combustion turbines is currently contracted to DWR, and is currently assumed for purposes of the analysis conducted for this study not to be available to CCSF.

Community Choice Aggregation Draft Implementation Plan

Chapter 5: Municipal Financing

Prepared
By
The City and County of San Francisco

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1. BACKGROUND

Ordinance 0086-04 – Establishing a Community Choice Aggregation (CCA) Program – was enacted into law on May 27, 2004. Section 3, Paragraph B of this ordinance directed SFPUC and SFE to work with City finance staff to determine how Proposition H bonds may be used to augment CCA by providing financing for renewable energy and conservation projects, including a bond-repayment schedule based on anticipated revenues collected from monthly electric bills and other sources.

2. RENEWABLE ENERGY REVENUE BOND PROPOSITIONS PROVIDE A CCA OPPORTUNITY

On November 6, 2001, San Francisco voters approved two renewable energy revenue bond propositions. Proposition B authorizes the City to issue up to $100 million in revenue bonds or other forms of revenue financing to finance the construction of solar and other renewable energy facilities and to fund energy conservation facilities and equipment for City agencies.

During the same election, voters also approved Proposition H – a Charter amendment allowing the Board of Supervisors to issue revenue bonds to buy, build or improve renewable energy facilities or energy conservation facilities without voter approval.

While passage of measures may appear redundant at first glance, in proponent's ballot argument for Proposition H they clarified that Proposition B bonds were restricted to government facilities only. Thus, the City currently has voter approval to authorize up to $100 million in revenue bonds subject to the constraints imposed by Proposition B.

In Section 2 of Proposition B, it was specified that the cost that City agencies could incur over the life of the technologies could not exceed the amount that the agencies would have otherwise paid for such costs absent the improvements and/or facilities. While this proposition does not define the term "costs," the Controller's Statement accompanying the ballot proposition indicated "… the cost of these bonds cannot result in power rates charged to the City departments that exceed the power rates that are otherwise projected to be in effect."

Proposition B imposed additional conditions with respect to the payment of any solar energy revenues bonds. Specifically, Section 3 specified that only the revenue produced and any costs avoided by the bond-financed improvements or facilities should be used to repay the bonds. As specified in Proposition B, the City would repay the principal and interest on the bonds from revenue generated and saved by the proposed facilities. Given the limitations indicated above, it is clear that Proposition B bonds cannot be used for CCA purposes.

3. FINANCIAL MARKET ISSUES RELATED TO USE OF PROP. H BONDS

As mentioned above, Proposition H presented a financing opportunity for renewable energy generation facilities and energy conservation projects in San Francisco. Proposition H did not specify the institution responsible for program implementation although subsequently an ordinance authored by Supervisor Ammiano directed the SFPUC to assume responsibility for a pilot solar program. The information provided below provides a general background on municipal bond financing as well as describing the steps that need to be taken in order for Hetch Hetchy Water & Power ("HHWP" or "Hetchy") or a new CCA agency to issue bonds under the authority of Prop H.

3.1 Why does SF Need to Issue Bonds and What Are They?

Frequently government agencies need to undertake capital projects for which they do not have sufficient cash in their treasury. Municipal bonds are debt obligations issued by government entities to raise money to finance the cost of capital projects for the public good, such as schools, highways, hospitals, and, in the case of Proposition H, renewable energy and energy conservation projects. These projects usually have useful lives that span a couple of decades and it is generally considered appropriate public policy to spread the costs of such facilities over this timeframe.

Municipal securities can be either long- or short-term issues. Large capital projects, such as installation of wind generation facilities would obviously have a useful life greater than one year and are therefore suitable candidates for long-term bonds.

There are two basic types of municipal bonds – general obligation bonds and revenue bonds.

3.2 Types of Tax-Exempt Municipal Bonds

i. General Obligation Bonds

General obligation bonds (or "GO" bonds) are secured by the full faith and credit of the issuer and are supported by the issuer's ability to use its taxing power for repayment. These types of bonds are considered the safest form of municipal investment and generally carry lower interest rates. GO bonds are more flexible for local governments because the issuer can repay the bond with a variety of tax sources.

In San Francisco, general obligation bonds must be approved by voters and are repaid through property taxes. In addition, the City maintains a "prudent debt level" or debt capacity level of three (3) percent on the net assessed value of properties in the City and County. The Mayor's Office of Public Finance oversees the City's debt and monitors when debt is being retired or undertaken so that the debt level is not exceeded.

ii. Revenue Bonds

Revenue bonds, contrastingly, are secured by revenues derived from fees or charges associated with the operation of an enterprise, such as the water enterprise or the clean water enterprises. In San Francisco, service charges to both water and sewer customers are calibrated to be sufficient to not only operate such enterprises but also to repay obligations associated with the construction or reconstruction of facilities necessary to operate those enterprises. For instance, current sewer service charges are financing improvements made to the sewer system to comply with federal Clean Water Act enforced by the U.S. Environmental Protection Agency.

The amount of revenue bonds that may be issued by an enterprise is generally limited by certain covenants contained in bond indentures. A common covenant is the requirement to generate net revenue (revenues less costs for operation and maintenance) sufficient to cover annual debt service by 1.25 times. For example, if an enterprise has an annual debt service of $1.0 million, then the coverage covenant in the indenture would require that the enterprise generate a minimum of $1.25 million in net revenue (1.25/1.0 = 1.25). When considering the issuance of new debt, an enterprise has to certify that projected revenues, which include potential rate increases, would be sufficient to meet the coverage test for the increased amount of annual debt service resulting from the issuance of additional debt.

3.3 Why Would an Investor Purchase Municipal Bonds?

When an investor purchases municipal bonds, they are in effect lending money to the issuer who promises to repay the money with a specified amount of interest (usually in semiannual payments) and the principal by a specific maturity date. Investors find municipal bonds attractive because they provide among other things: 1) income that is free from federal, and in some cases, state and local taxes; 2) a high degree of safety with regard to payment of interest and repayment of principal; 3) a predictable stream of income; and, 4) marketability in the event that one needs to sell before maturity.

3.4 Prop H Bonds Are Not Suited To Finance Energy Conservation

The proposed RFP language of Ordinance 0086-04 regarding use of Prop H Bonds to finance conservation projects may be particularly challenging. Assuming a standard approach to financing conservation projects is assumed in the Ordinance. For example CCSF could attempt to use Prop H bonds to create a loan program so that residents and businesses in a CCA program could undertake energy efficiency projects at low interest rates, however this approach would conflict with the non-taxable aspect of municipal bonds. The State of California Proposition 218 prohibits the use of public funds for private purposes, given that dollar conservation savings would accrue to private entities in a CCA program the income to bond investors would now become taxable. This would likely limit investor interest in purchasing these types of bonds

Additionally, with this type of use, the CCA would have to assess the creditworthiness of private parties participating in this type of conservation financing program. This could result in the CCA assessing a higher interest rate to participants due to overall creditworthiness concerns. Those parties interested in pursuing this program may

ultimately find that market interest rates may be superior to loan rates offered by the CCA.

3.5 What Needs to Happen in Order for SF to Issue Prop. H bonds?

When someone invests in a bond, their primary concern is the issuer's ability to meet its financial obligations. Issuers of municipal bonds, in general, have a strong record of meeting both interest and principal payments in a timely manner. Issuers disclose this information to investors through an official statement prepared when the securities are being sold.

Investors rely heavily on credit (or bond) ratings by agencies such as Standard & Poor's, Moody's Investor Services and Fitch Ratings.

Proposition H does not contain language specifying a funding mechanism or enterprise for the repayment of any renewable energy or conservation bonds. For purposes of this Draft Implementation Plan, and given its relative expertise with respect to energy matters, it is assumed that the SFPUC's Hetch Hetchy Water and Power enterprise (Hetchy or "HHWP") is the agency to secure the issuance of such bonds. At this time, however, HHWP does not have a bond rating. However, the other two SFPUC enterprises, Water and Clean Water, do have their own credit and bond ratings. Clearly the Water and Clean Water enterprises could not demonstrate a nexus of costs and benefits from its enterprises to the CCA enterprise. Hence HHWP would need to obtain a bond rating before issuing any bonds for CCA purposes.

3.6 Restrictions Imposed by the Special Fund Doctrine

There is also a state constitution issue that provides an important context for the issuance of Prop H bonds. Article XVI, Section 18 of the State Constitution, provides that before a public entity may incur an obligation in excess of its yearly income, it must have the assent of two-thirds of its qualified electors voting at an election to be held for that purpose. Thus, local entities must operate on a pay-as-you-go basis unless two-thirds of the electorate assents to the incurrence of debt.

A notable exception to this is the so-called "special fund doctrine." Under this exception, local entities can incur indebtedness without obtaining two-thirds voter approval provided the local entity pledges only user charges or other revenues from an appropriate enterprise to repay the debt. Simply put, under this exception, a debt is not created if it is not payable from the general fund supported by the taxing power of the local entity pledged to the repayment. Thus, Prop. H does not create a General Fund debt as long as any bonds issued are repaid from revenues of an appropriate enterprise and not San Francisco's general fund.

Assuming that Hetch Hetchy is the enterprise of choice to undertake potential projects to be financed with Prop. H bond proceeds, and assuming that it has a credit rating (which it

currently does not have), it must comply with the special fund doctrine. Implicit in this doctrine is that Hetchy has a reliable source of revenues derived from its fees and charges as a CCA. Therefore revenues from rates charged and received by CCA would need to be sufficient to cover the capital costs of any proposed projects.

While another source of revenues for Hetch Hetchy are revenues from City departments for sales of Hetch Hetchy power. However, it is highly likely that a court would simply characterize those revenues as general fund monies, i.e., taxes, the net effect of which is to negate a special fund ruling for Hetch Hetchy. In anticipation of this, the SFPUC clearly has to exclude the revenues from other City departments in any calculations of bond repayment for a CCA

Therefore if Hetch Hetchy is the enterprise to act as the City's CCA, then it has to raise revenues from rates collected from CCA electrical customers that would repay the CCA renewable energy programs. Nonetheless, Hetch Hetchy, as a new credit in the marketplace, would still need to obtain a rating from the rating agencies in order to issue bonds.

3.7 CCSF Bond Program Requirements

In general, prior to placing a measure on the ballot concerning bonds, most City departments prepare a bond program report that contains the following information: the program's goals and objectives; a detailed list and description of projects to be undertaken; and, an engineer's estimate of the project's costs including soft costs. The report is then sent to the Capital Improvement Advisory Committee (CIAC) made up of high-ranking city officials, both elected and appointed, for their review and recommendation. Once the CIAC reviews a bond measure, the bond program report is given to the Board of Supervisors for their consideration. In determining whether or not to place a bond measure on the ballot, the Board of Supervisors may or may not agree with the CIAC's recommendation and either place or not place a measure on the ballot. If Hetch Hetchy were to issue bonds via Prop. H, it would have to go through the Commission, the CIAC and then to the Board of Supervisor but not the voters.

Given that Prop. H permits financing for acquisition, construction, installation, equipping, improvement, or rehabilitation of renewable energy facilities with approval of the Board of Supervisors, then it would be likely that the Board would require a similar report prior to approving a bond issuance under Prop. H. This document is also made available to investment banking firms so that they can understand the projects that the bonds will be used to finance.
It is state law that revenue bond proceeds cannot be used to finance operational shortfalls or administrative costs. The Mayor's Office of Public Finance has given clear directions to City departments that these types of expenditures are not an eligible use of bond proceeds. Thus, if the City's CCA were to incur a two-year cumulative operational deficit of $125 million as stated in Chapter 4, it would be illegal to use revenue bond proceeds to cover this deficit.

Furthermore, since the City became aware of that the San Francisco Unified School District had used general obligation bond proceeds to cover administrative expenditures, the Mayor's Office of Public Finance has made it City policy that this practice was forbidden.

In other cases whereby it would not be illegal to use revenue bond proceeds to finance operational activities, jurisdictions wanting to issue revenue bonds would be required to disclose this information to the investment firm underwriting the bonds and this would negatively impact the jurisdiction's credit rating.

3.8 What is the Importance of Having a Credit Rating?

While the bond program report provides the investment banker and individual investor with information related to what bond proceeds would be used for, the investor's primary concern will remain whether or not the issuer's is able to meet its financial obligations. Historically, issuers of municipal bonds, including the City and County of San Francisco, have an outstanding record of meeting interest and principal payments in a timely manner.

The financial condition of issuers are disclosed through official statements or offering circulars which are available through brokerage firms, the Internet, or from a library that archives official statements from businesses. Issuers also provide continuing disclosure about their financial condition through nationally recognized municipal securities repositories.

Another way to evaluate an issuer is to examine its credit rating. The top three rating agencies are considered to be Standard & Poor's, Moody's Investors Service, and Fitch Ratings. An underlying credit rating would reflect the issuer's fundamental credit quality, as opposed to a bond rating, which is a rating assigned to a particular bond issue and reflects particular security provisions of that issue. For example, the Clean Water Enterprise purchases bond insurance so that its bond issuances are rated "AAA" but its underlying credit rating is "A1".

Other business entities, such as banks and brokerage firms, also conduct their own research and analyze municipal securities. Generally speaking, bond ratings for revenue bonds give investors an indication of the project's ability to generate the revenue stream required to repay the bonds used to construct it.

As can be seen from the table below, having a credit rating of "BBB" by Standard and Poor's and Fitch, or "Baa" by Moody's are generally considered "Investment Grade" because they would be suitable for preservation of investment capital.

Credit Ratings

Credit Risk	Standard & Poor's	Fitch	Moody's
Prime	AAA	AAA	Aaa

Excellent	AA	AA	Aa
Upper Medium	A	A	A
Lower Medium	BBB	BBB	Baa
Speculative	BB	BB	Ba
Very Speculative	B, CCC, CC	B, CCC, CC	B, Caa
Default	D	D	Ca, C

While credit and bond ratings provide the investor with financial information to make an informed investment decision, they are not the only information an investor would analyze. Credit ratings do not account for market trends. In general, because the interest rate on bonds, also called the coupon rate, does not change during the life of bond, the market price of that bond changes as market conditions change. If an investor chooses to sell their bond prior to its maturity, that investor may receive more or less than their original price. Consequently, the investor would need to have an understanding of how the direction of interest rates would affect the value of their holdings.

Having an investor-grade credit rating is also beneficial to the CCA entity. If the CCA is given an investor grade rating by the three rating agencies, then it is likely it will be given a coupon rate that is relatively low, meaning that there will be less debt service being passed onto to ratepayers to pay. This is a highly desirable outcome for the CCA, as it would help the CCA keep costs low.

3.9 What is the Importance of Having a Bond Rating?

Principal buyers of municipal securities are large mutual funds. Most, if not all, mutual bond funds are prohibited from buying unrated securities. There may be some, but they are in the distinct minority. So, first, a credit rating enlarges the pool of potential purchasers of the City's revenue bonds. Also, bonds with credit ratings carry lower interest costs than bonds without credit ratings. So, assuming an investor could be found to purchase the securities, the interest cost may be prohibitive relative to the market place.

Because revenue bond analysis encompasses a myriad of specializations, financial analysts tend to specialize in industries, such as utilities, housing, or transportation. This allows them to stay abreast of trends that occur in each of their respective industries on both a regional and national basis. The enterprise that will be responsible for the repayment of the debt is generally subject to a thorough financial analysis as well as an assessment of the economic strength of its service area. The legal provisions of the trust indenture are also scrutinized as this provides bondholders with protection from risks such as dilution of the security through the issuance of additional bonds. Regardless of which party the financial analyst is working on behalf of, the bottom line is the analyst's main job is to evaluate the issuer's credit worthiness, in this case for example Hetch Hetchy or the San Francisco CCA.

3.10 Rating Criteria

As a matter of course, the financial analyst will be reviewing such standard items as the debt itself, and the economic, financial, and management/legal structure of the issuer. In addition, an economic analysis of the demand for services, the level of costs, operating efficiency and the actual and potential level of competition will also be undertaken. Lastly, the financial analyst will be evaluating the economic health of the service area. With respect to electric utilities, financial analysts will also examine the diversity of the types of fuels in the supply portfolio in addition to making a determination of whether or not the power supply itself is adequate to support the area's projected growth.

Because revenue bonds are often protected by a number of legal and financial agreements, analysts on behalf of bondholders will scrutinize these documents as closely as they do the projects for which the bonds are being issued. The first step of this analysis is to examine the provisions of the bond indenture that are summarized in the official statements of the issuer, however, a good analyst will also closely scrutinize the bond indenture itself.

3.11 The Bond Indenture

Of interest to the financial analyst will be the flow of funds language contained within the bond resolution. This language sets forth the order in which funds generated by the enterprise -- in the case of the Hetch Hetchy, monies raised from rates, will be allocated to various purposes. In general, funds are first used to pay for operations and maintenance expenses then for debt service (principal, interest, and term amortization) as well as to establish reserves.

With respect to accounting, the financial analysis will assume that all monies collected from ratepayers will be deposited into the revenue fund. With respect to operations and maintenance, the industry rule of thumb is that one-twelfth of an enterprise's annual budget is shifted from the revenue fund to the operations and maintenance fund each month. Other accounts to which revenues are distributed are discussed below.

Sometimes a jurisdiction will also have a debt-service fund whereby money is set aside monthly to equal the amount necessary to meet the annual debt service. This fund is frequently broken down into two accounts – one for principal and one for interest. Some jurisdictions usually specify in their resolutions that cash be transferred to this fund immediately before the semiannual coupon is to be paid. Other jurisdictions opt to have separate bond-redemption funds while others may have a note-repayment fund or a sinking fund account.

The debt service reserve fund is usually set up initially with bond proceeds. Reserve funds are only tapped if the debt-service fund is insufficient to meet annual payments. The reserve fund is usually set at an amount equal to six months or one year's debt service, with a six-month reserve usually requested for issuer's with a stronger credit rating. Some issuers with a strong credit rating can forego a reserve fund and may use a surety bond or other substitute.

Other miscellaneous funds that a jurisdiction may establish are the reserve maintenance, the renewal and replacement fund, and a construction fund for new projects. At the recommendation of its consultants and depending on the nature of the enterprise, some local jurisdictions may also have need to create a reserve maintenance fund to meet unanticipated maintenance expenses. The renewal and replacement fund is established to replace equipment and to make routine repairs. A regular payment is made into this account as budgeted by the enterprise. If new construction is planned, a separate fund is created to pay for the expansion.

A bond resolution can also itemize where the balance, or surplus, revenues should be directed. These funds could be used to redeem bonds or reduce tax payments. Many municipalities, including San Francisco, use surplus funds from enterprises for general fund uses. The bond resolution can restrict this use as well as specify what kinds of securities can be purchased with excess funds.

3.12 Rate Covenants

In addition to a well-designed flow of funds and the size of reserves, investors seek other assurances that an issuer will repay their debt. In the case of user-charge bonds, such as those often used by utilities, credit rating agencies often require a rate covenant such that the issuer pledges that rates will be set high enough to meet operation and maintenance expenses, renewal and replacement expenses and debt service by a predetermined margin, known as the debt service charge. During the SFPUC's recent sewer rate hearings, there was concern expressed that the SFPUC could be threatened with a court order to raise its rates in order to ensure that its operational expenses for its Clean Water Enterprise would be met. This concern was justified as the Clean Water Enterprise's outlook was raised from "negative" to "stable" in January 2003.

Rate covenants vary greatly based on the type of bonds. Bonds issued for stable monopolistic enterprises such as water and sanitation are often have a lower rate covenant than bonds that face competition. Because Hetch Hetchy will be a new issuer any bonds that issued prior to the CPUC establishing rules that relate to a CCA maintaining a customer base and any other considerations related to the overall the level of competition for CCA customers could lead to a higher bond covenant for both Hetchy or a CCAs seeking bond financing ahead of market development.

Additional covenants might include provisions for insurance, periodic reviews by outside experts, a timetable for conducting independent audits, or guarantees that no free or highly discounted services will be offered to favored customers.

4. WHEN WOULD BE THE BEST TIME FOR THE CCA TO ISSUE REVENUE BONDS?

As mentioned above, credit agencies will be evaluating the financial and economics of the market of the CCA. The importance of stability and predictability of the operating environment are critical pieces of information and in the long will effect the pricing of bonds issued by the CCA. Further, the California Public Utilities Commission has yet to

make its rulemaking decision on Phase II, which encompasses issues impacting the stability and predictability of the CCA's market. One of the most important issues to be determined by the CPUC is that of switching rules that will help define the stability of the CCA's potential customer base.
The SFPUC believes that the issue of the timing of potential bond investments in renewable projects might be best addressed within the context of the Hetch Hetchy business plan and after the CCA has been implemented, and customer opt-out has concluded and the CCA has established a partnership with an ESP. At this juncture, the timing, the size, and the integration of any CCA bond financed renewable projects with the ESP portfolio will be much clearer.

5. OTHER FINANCIAL ALTERNATIVES

5.1 Certificates of Participation

Another financial tool available to municipal jurisdictions is the use of certificates of participation. A certificate of participation (COP) is an arrangement in which investors purchase certificates that entitle them to receive a share, i.e., a participation, in the lease payments from a particular project. Because the lease payments are passed through the lessor, the tax advantages are kept intact for the certificate holder.

The advantage to the municipal jurisdiction to using a COP is that it is not incurring debt in the traditional sense because it is using a lease that contains either an acceptance or rent abatement clause or the lease is renewable subject to an appropriation risk. The abatement clause provides that if the facility cannot be utilized, e.g., because of damage caused by a natural disaster or construction delays, then the lessee cannot be compelled to make the lease payments. This clause makes the lease payments "fees for services" as opposed to debt, but the obligation to make payments remains a long-term obligation. There are usually insurance provisions that protect against abatement risk. In addition, if the COP is carefully structured, it should not exceed the costs associated with bond financing.

The City and County of San Francisco uses COPs sparingly since voter approval is not required as it is with other General Fund-related debt. It is general City practice to use COPs to purchase land and construct office space. The City also requires that projects financed using COPs be revenue neutral and that they be reviewed by the CIAC. Projects using COP financing have included the Courthouse, San Bruno Jail and Juvenile Hall. With respect to the Courthouse, there was a fee structure developed that provided a revenue stream thus keeping that project to remain revenue neutral. With respect to San Bruno Jail, the issue to rebuild the jail with general obligation bonds was rejected by voters four times. Therefore, the City used COPs in order to bring the building up to code and to comply with health and safety standards required by the federal and state governments.

5.2 Marks-Roos Act – Joint Exercise of Powers Authority

This Act provides Joint Powers Authorities ("JPAs") with broad powers to issue bonds for a wide variety of purposes. The law, originally enacted in 1985, was designed to facilitate local bond pooling efforts that would allow local agencies to achieve lower costs of issuance through spreading fixed costs across a number of small issues. These bonds can only be issued by JPAs, which are special government entities created under the Joint Exercise of Powers Law by agreement between two or more "public agencies." The parties to the Joint Exercise of Powers Agreement are called "members" and some members may be "captive" entities of jurisdiction, e.g., a JPA made up of a city and its own redevelopment agency. Other JPAs are multi-jurisdictional and issue bonds for all or some of its members.

Marks-Roos bonds are bonds of the JPA that issues them, as opposed to bonds of the member agencies. Thus, member agencies are not directly liable or otherwise obligated on the bonds unless they expressly agree to assume such liability.

In order to issue bonds using the Marks-Roos Act, the local agency for which the bonds are being issued must articulate the "significant public benefits." These benefits are defined to mean: 1) demonstrable savings in effective interest rate, bond preparation, bond underwriting, or bond issuance costs; 2) significant reductions in effective user charges levied by a local agency; 3) employment benefits from undertaking the project in a timely fashion; and, 4) more efficient delivery of services to residential and commercial development.

Policymakers may want to investigate the potential for a Marks-Roos JPA for the CCA either as a JPA with captive members, i.e., the City and County of San Francisco and another state-mandated agency, such as Caltrain or BART, or as a member of larger organization perhaps made up of other Bay Area municipalities wishing to become CCAs.

Community Choice Aggregation Draft Implementation Plan

Chapter 6: Solicitation and Contracting Options

Prepared for
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1. OBJECTIVE AND SCOPE

This report reviews the solicitation and contracting options available to the City and County of San Francisco ("CCSF") under a Community Choice Aggregation Program. The report discusses the various issues related to a CCSF RFP and contract that would need to be addressed if the CCSF established a CCA Program. It also identifies the likely contractual obligations and options the CCSF will have with other parties under a CCA Program, including PG&E and third parties. As a means to educate readers unfamiliar with CCA and power procurement, the report provides descriptions of the various terminology, concepts, risks and obligations associated with contracting for electricity generation service in competitive markets.

The report is organized into the types of solicitations and contracts that the CCSF could enter into, starting with a general description of RFPs. The report sections are:

- RFP Development and Objectives
- Full Requirements Electricity Service
- Supporting Services
- Renewable Resource Development and Supply
- Glossary
- Appendix A: Standard Contract Provisions for Electric Generation Service
- Appendix B: List of Sample RFPs and Supply Contracts

2. RFP DEVELOPMENT AND OBJECTIVES

2.1 Contracting Options

Depending upon CCSF's objectives and desired organizational scope, a CCA Program could entail three general categories of responsibilities for the CCSF and new contractual relationships with third parties. The three categories are:

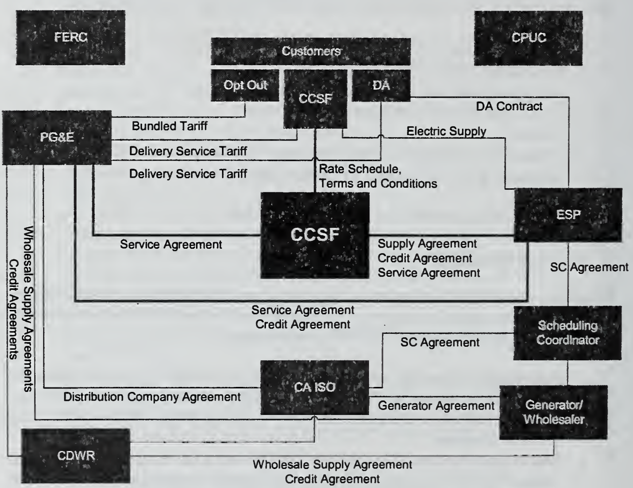
- **Full Requirements Electricity Supply**. This refers to the general contractual relationship in which the CCSF would purchase electricity generation service, including renewable energy or attributes, for use by its residents and businesses in the CCA Program
- **Supporting Services.** This refers to the contractual relationships used to meet various functional responsibilities that are required to interact and transact with customers, ESPs and PG&E, which could include rate design, customer service, energy efficiency program management, contract administration, etc.
- **Renewable Energy Resources Development/Ownership**. This refers to the various contractual responsibilities the CCSF assumes, should it finance, own and possibly operate energy resources. These resources are likely to be renewable energy production facilities.

There are numerous responsibilities and requirements under each of these categories. The CCSF is expected to have numerous options for assigning these responsibilities and requirements to either itself or to a third party.

2.2 Contracting Parties

There are three primary contracting parties that the CCSF would need to transact with under a CCA Program: customers (residents/businesses), Pacific Gas & Electric ("PG&E") and ESPs. There are numerous other parties that could have a direct or indirect impact on the solicitation and contracting process and outcomes. These parties are identified in the figure below for full requirements electricity supply procurement.

Figure 1. Contractual Relationships for Full Requirements Supply

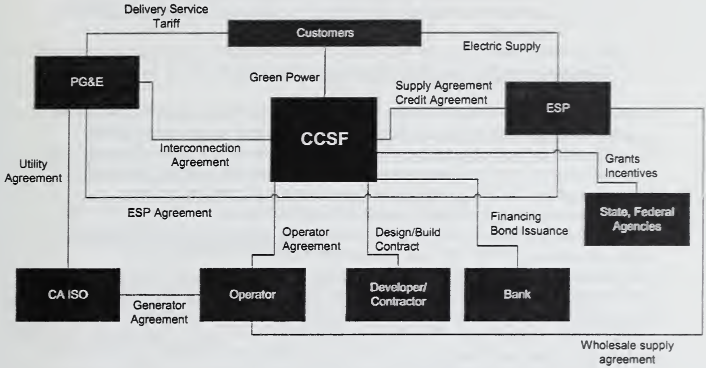


The primary contractual arrangements under a CCA Program are the CCSF-ESP Energy Supply Contract, Credit Agreement and perhaps Service Agreement, the PG&E Service Agreement with the CCSF and/or ESP and Rate Agreements between the CCSF and Participating Customers.

There are likely to be a different set of contractual relationships for renewable resource development, including a different set of counter parties. The contractual parties that are

likely to be involved in renewable resource development are illustrated in the figure below.

Figure 2. Contractual Relationships for Renewable Resources



2.3 Maximizing RFP response

Ultimately, the response to a CCA Program solicitation will be dictated by the opportunity it creates for potential bidders. The opportunity will be defined, in part, by circumstances beyond the CCSF's control, such as regional natural gas prices the regulatory framework, and the business strategies of ESPs. Moreover, the RFP responses should provide, over time, a more attractive alternative than PG&E's bundled service, which, in large part, will be dictated by wholesale electric market prices and the Cost Responsibility Surcharge (CRS) etc. However, there are several specific provisions of the RFP that will likely have significant impact upon the response, assuming external factors permit.

Generally speaking, the CCSF must strike a balance between precision and ambiguity in the language of the RFP. At a minimum the CCSF will need to specify major risks and obligations, and assign them to the appropriate parties. These risks include price, volume and credit risks and are discussed in further detail in the next section. Other examples could include:

- Identify the CCSF's specific preferences (e.g. resource mix, functional responsibilities, etc.);
- Specify proposal evaluation criteria, e.g. the ESP must meet the Resource Adequacy Requirements set by the CPUC for LSEs;

- Provide flexibility for ESPs to manage risks and obligations;
- Avoid provisions perceived as highly or unnecessarily risky by ESPs, such as termination for convenience clauses and limits on certain material change provisions (e.g. changes in key regulations);
- Possibly waive SF Administrative Code sections that would constrain electricity-contracting flexibility, e.g. Section 21.19 and 21.35 (check numbers).

2.4 Comments on Proposed RFP Language in Ordinance.

Ordinance 0086-04 proposes RFP language that may negatively impact RFP responses, or at the least raise many clarifying questions from potential responders to CCSF. Requiring bids to "include proposals for rate design with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid" (Section 4 – D) appears premature. First it appears to presuppose that RFP responders will be responsible for the CCA renewable energy, conservation and energy efficiency programs installations. However Section 3.1 of the Ordinance asks that the Draft Implementation Plan address the "appropriate scope and organizational structure for the program its operations and it's funding". This latter section therefore invites the Plan to propose examination of options related to e.g. conservation and energy efficiency programs run by CCSF staff, and renewable energy projects owned and financed by CCSF via e.g. bond funding. Second in preliminary discussions with potential respondents to a CCSF RFP (ESPs) the SFPUC staff has been informed that a breakdown of costs and profits associated with providing "various components of its proposed service package", is likely to prove an extremely burdensome task to respondents. The SFPUC Staff believe that many respondents will not go beyond revealing a generic profit margin in its bids e.g. a 1% mark-up on all kWh purchased for a CCA, as well as basic information about costs for operational requirements. Third this section of the RFP appears to presuppose that an ESP is solely designing rates for a CCA. This appears to contradict the requirements of AB 117 that a CCA must provide for "disclosure and due process in setting rates and allocating costs among participants". While the ESP certainly will have a role in determining rate design for CCA customers final review and decisions regarding rate design rest with the CCA.

Similar problems are found with the language requesting city staff, in the implementation plan, to provide "Recommended contract provisions that will provide financial incentives to the City's Electric Service Provider, if one is selected, to accelerate deployment of and/or expand the energy efficiency and renewable energy components of its proposed energy portfolio." (Section 3-9 V). Again this section appears premature in that it presupposes that it is the ESP that is responsible for deployment of energy efficiency and renewable energy projects.

Finally the Ordinance requires a Draft RFP to a provision that ESP's post a bond or demonstrate insurance to cover the cost of reentry fees to deal with the circumstance that customers are involuntarily returned to PG&E service. The SFPUC staff note first that

most active ESP's on the CPUC registration list have posted such a bond to serve their existing customer base. However depending upon the additional size of bond or proof of coverage required by the CPUC for CCAs (a CCA Phase 2 proceeding issue) it is likely that this requirement will increase the costs of the bids offered by ESPs.

2.5 Solicitation tactics

There are several tactics that can be used to ensure that the solicitation process yields the maximum level of qualified bids, barring external circumstances. Examples include:

- Develop comprehensive prospective bidders list
- Communicate to potential bidders early and often; maintain solicitation website
- Solicit feedback on a draft RFP and supply contracts from potential bidders
- Develop and disseminate robust load and customer data
- Provide the latest information on regulatory requirements

2.6 Multiple RFPs and multiple awards

Depending upon the objectives and scope of the program, multiple RFPs may be warranted. Given the differences between full requirements purchases and energy resource development, the use of two separate RFPs may be warranted to ensure the best possible responses for each.

For a given RFP, multiple awards may be warranted, depending upon the objectives of the RFP. In general, multiple awards decrease the default risk, but increase the administrative burden

2.7 Program termination

CCSF will expend considerable political and financial resources to become a CCA and will likely enter into a multi-year contract with an Energy Service Provider which could be worth as much or more than a billion dollars. Investing in renewable energy and energy efficiency projects using Prop H Bonding will also involve a multi-year commitment from CCSF. Termination of the CCA program would involve complex and costly unwinding of these commitments.

Contract termination provisions are addressed in Sections 3.14, 3.15 and 3.17. In the case of ESP failure or breach of contract, CCSF would likely pursue its contractual rights while also signing a new contract with an alternative supplier.

Circumstances that could precipitate the termination of a CCA program include:

- **SF CCA Power Prices Are Considerably Higher Than PG&E's** for an extended period of time. This leads to customers electing to leave the CCA (despite switching rules that might be onerous), or alternatively calling for transfers from the general fund to decrease electric bills. In general this creates political pressure for CCSF to cease offering a CCA program.

- **A Local Natural Disaster** (e.g. significant earthquake) could also disrupt the distribution system, making it impossible to sell power resources to the community. This could cause substantial financial stress on the CCA (and of course on all city facilities), but presumably force majeur clauses of power contracts (or generation debt if City-owned) would apply. Hence it does not appear that a local natural disaster itself would cause CCSF to terminate the CCA program.
- **Overall Market Failure Preventing Replacement of the ESP** could require CCSF to terminate its contract and return customers to utility service.

In all of these cases, there are some common issues and impacts:

- Notification must be made to all CCA customers;
- Customers must be switched back to utility service, according to rules not yet developed by the CPUC.
- Legal proceedings are likely to be required to address contract issues with the ESP and possibly generators owned or contracted through CCSF.
- Legal proceedings are likely to be required to address any bonding commitments made for any power production where CCCSF is a part owner.
- CCSF will likely need to perform staff reassignment or lay-off.

3. FULL REQUIREMENTS ELECTRICITY

3.1 Competitive electric markets overview

Retail and wholesale power markets involve complex and evolving regulatory and commercial structures. Full treatment of power market structures is beyond the scope of this analysis, but it is useful to review the basic building blocks for transacting in competitive power markets.

Retail electric markets are defined by the sale to end use customers. The product sold is generally referred to as "Full Requirements" electric supply and is discussed in detail in the next section. Retail providers of electricity are also referred to as Load Serving Entities (LSEs), a class of organizations authorized or required to supply electricity to retail customers located within a particular electrical system. Wholesale electric markets are defined by the sale to parties other than end use customers. Numerous electricity products are bought and sold in wholesale markets. We summarize them below.

Forward markets. Wholesale market participants have numerous options to either transact in advance of actual consumption or transact at the exact time the customer consumes the electricity. Forward contracts refer to transactions where delivery occurs at a specified future date, rather than in the present. Forward markets are generally less volatile than spot markets (discussed below) and provide efficient methods for parties to manage or hedge risks. All forward contracts specify the type, quality, quantity, delivery date, delivery location, price and term of the power to be purchased and sold. Futures contracts are sub-set of forward contracts that are bought and sold through exchanges and

have specific standardized contractual attributes that make it a fungible and liquid product.

Derivatives. Derivatives are also forward market products. A derivative is a transaction that is designed to create price exposure, and thereby transfer risk, by having its value determined from the value of an underlying commodity (e.g. electricity). Derivatives generally do not involve the transfer of title (e.g. physical commodity ownership), and thus can be thought of as creating pure price exposure, by linking their value to a notional amount of the underlying commodity. Examples of electric derivatives include call and put options, swaps (e.g. fixed for floating price), weather options and futures contracts.

Spot Markets. Spot markets are physical markets. They refer to real time and day ahead transactions for electricity and are generally managed by a grid operator (e.g. California Independent System Operator). The grid operator coordinates the market with the physical dispatch of generating resources to meet demand. Load Serving Entities purchase from spot markets to meet balancing energy needs and in some cases to serve a portion of scheduled load.

Resource Types. Buyers and sellers also specify generation resource types that correspond to fluctuating load patterns. Resource types are generally correlated with technology and fuel type and are integral to contracting for full requirements service. The primary categories of resource type are baseload, intermediate, peaking, as available, firm, and odd lot products. Prices and costs generally increase from baseload to intermediate to peaking and from as available to firm.

Pricing. There is a wide array of pricing structures utilized in both retail and wholesale markets. In retail markets, there are three primary pricing units: energy charge (cents/kWh), demand charge ($ per kW) and customer charge ($ per account). Beyond these basic pricing units, the many pricing structures utilized in competitive markets provide flexibility in assigning risk to either the ESPs or the buyer. The table below categorizes retail pricing structures into simple, complex and option pricing.

Table 1. Options for Pricing Retail Electricity Generation Service

	Pricing Types	Description
Simple	Percent off tariff or guaranteed savings	Provides for guaranteed savings off utility default service. Price will vary if utility price varies. Price will remain constant if utility price is constant.
	Shared savings	Retail price usually tied to default service pricing approach that results in savings calculation and sharing between retailer and customer of savings
	Fixed energy price	Cents per kWh price for generation only with no demand or fixed standing charges. Delivery of wires charges are either passed through or billed separately.
	Fixed bundled price	Single cents per kWh price for both generation and wires service. May or may not have a fixed monthly charge or a demand charge.
	Fixed energy and capacity	Fixed cents per kWh energy charge plus fixed monthly charge or variable peak demand charge.
Custom or Complex Products	Electric indexed price	Price subject to variation based on index, usually a nearby liquid wholesale electric hub.
	Gas indexed price	Heat rate formula used to set price level results in price that varies by price of natural gas.
	Wholesale blocks	Fixed prices for power supply that is NOT full requirements. Customer buys shaped energy, including ancillary services and transmission, separately.
	Fixed-variable combination price	Price is fixed up until some strike price (based on usage, demand, wholesale price, etc.), then index price is applied.
	Time differentiated fixed price	Time-of-use pricing varies by time of day or type of day. This is often termed multi-part pricing.
	Real-time or dynamic price	Price varies in short-time intervals (e.g., hourly spot market price). Products typically structured in ISO markets using day-ahead or hour-ahead spot market prices.
	Contracts for Differences (CFDs)	Price is fixed under financial contract, but physical supply is purchased through spot markets. Variations between spot market price and retail contract price are then settled
	Block or usage-tiered price	Price level varies by amount of usage; could be tiered usage or other mechanism.
	Consumption-adjusted price (collars, caps, etc.)	Fixed price based on specified consumption parameters (load factor, load shape, or periodic volumes). Variation outside specified parameters results in change in price level, usually through a market-based price.
Option and Risk Management Products	Trigger pricing (form of option)	At specified trigger price, retailer makes wholesale purchase for customer. Customer typically has load reduction capability or on-site generation.
	Curtailable/Interruptible price	Fixed term or indexed price that is discounted to allow retailer to exercise option to reduce load under certain conditions.
	Interruptible load and on-site generation options	Retailer pays customer for right to use customer asset (interruptible load, on-site generation) under certain conditions. Arrangement can be in form of revenue-sharing agreement.
	Swaps	Customer trades a product (e.g., natural gas) for electricity at an agreed-upon price
	Supplemental supply options	Provides holder (retailer or customer) with right, but not obligation, to buy ("call") or sell ("put") power at a set price. (Could be structured as a trigger price)
	Insurance products	Customer pays a premium to retailer for reliability or power quality. In case of reliability event, retailer (most likely through an insurance company) pays customer 'damages.'
	Integrated pricing	Price of energy supply, interruptible load, energy services, etc., bundled into a single, integrated price that may be in price per sq. ft. or some other non-commodity unit.
	Unit of output pricing	Price indexed to price of customer's product (customer sells product at higher price, power price goes up and vice versa). Retailer must hedge through relevant commodity futures markets. Enron offer this prior to bankruptcy.

3.2 Full requirements electricity supply

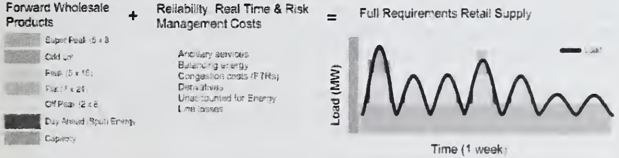
Electricity is a unique "product" with respect to how it is produced, delivered and consumed, since consumers (1) use it instantaneously on an as needed basis, (2) it travels according to its own unique laws of physics and (3) producers cannot store electricity cost effectively (i.e. power must therefore be produced at the exact same time it is consumed).

Given these unique properties, competitive electric markets demand the use of numerous rules, protocols and technologies to operate the system reliably, cost effectively and competitively. Consequently, a variety of specific products are utilized based on these rules and protocols to bundle together and allocate the risks of the electricity generation service that is ultimately used by consumers. This bundled or packaged service delivered to consumers is frequently referred to as "full requirements" electricity service. That is, electricity generation provided to end-users must be packaged together to meet the full set of technical, policy and business requirements. Most of these component products are bought and sold between market participants in wholesale markets or through electric grid operators.

Expected hourly consumption drives purchase requirements of various wholesale products for providers of full requirements electricity service. Expected consumption is quantified in the form of a load profile, usually hourly amounts of electricity measured in kilowatts or megawatts.

The figure below provides a simple illustration of the components to building full requirements retail service for a hypothetical load. The figure identifies several types of forward and real-time power products that may or must be purchased to serve retail load. Many of these components vary by retailer procurement strategy and market rules. Under a scenario where CCSF invests in a renewable generation facility e.g. wind power it is also vital that a "shaping" electric product is purchased on the wholesale market so as to take full economic advantage of the intermittent generation source (more here??)

Figure 3. Full Requirements Supply Illustration



The table below provides brief descriptions of the physical and financial components of full requirements electricity supply.

Table 2. Cost Components of Full Requirements Electricity Service

Cost Components	Description
Energy	The primary charge for electric service based upon the electric energy (kWh) consumed.
Capacity	Charges based on the reservation of generating resources. The California ISO does not currently require load-serving entities to purchase capacity, but is considering it. However, capacity can be a component of contracts in competitive wholesale markets.
Ancillary Services	Charges subject to FERC regulation for services provided by the grid operator to maintain reliability, including coordination and scheduling services, automatic generation control and support of system integrity and security
Transmission	Charges subject to FERC regulation for the physical use using transmission systems to move electricity from generators to loads.
Balancing Energy	Charges for energy not scheduled in advance that is required to meet energy imbalances in real-time.
Congestion	In wholesale markets with locational pricing, congestion charges are created when there is insufficient transfer capacity to move energy from one location to another.
Line losses	Amount of energy determined to be lost during the transmission of power through the electric grid. Although not an explicit charge, load-serving entities must procure more generation than what is consumed to account for losses.
Unaccounted for Energy	Charges to account for energy that has disappeared from the system either in extra line loss, theft, forecasting error, or unmetered sites.
Credit Risk Premium	The cost associated with late or non-payment of electricity service. A premium is typically applied to the price of electricity in proportion to the likelihood that the buyer will pay.
Open Position Premium	The cost associated with price volatility of electricity between the time a seller offers a bid and the time buyers agree to the purchase.
Volumetric Risk Premium	The cost created by the inability of sellers to precisely match the actual volumes consumed by their customers with the forecasted volumes, leaving the seller exposed to the purchase of electricity (and sale of excess) at a variable price while selling to customers at a fixed price. This includes shaping risk, migration risk, weather risk, forecasting error risk and weather risk.
Supplier Margin	The cost associated with the requirement that the electricity seller requires a profit.

3.3 Types of risks in electricity purchasing

Electricity buying and selling has numerous inherent risks, some unique to electricity and others similar to other commodities and products in competitive markets. A summary of the general categories of energy risk is provided below[1]:

- Market/price risk – the risk of loss due to changes in market prices of the value of a contract. This covers numerous aspects of price behavior, including volatility, correlation, illiquidity and inadequate price discovery.

[1] The risk categories and definitions are adapted from the Committee of Chief Risk Officiers' report "Introduction and Executive Summaries of CCRO Recommendations," Committee of Chief Risk Officers, November 19, 2002, www.ccro.org/pdf/intro.pdf.

- Volume risk – The risk of not being able to deliver a contractual amount of energy, including operations risk as well as the impact of other external uncertainties (e.g., weather, customer migration)
- Credit/default risk – the risk of loss due to a counter party defaulting on its commitment to pay or deliver on a contract
- Operations risk – the risk of loss resulting from energy assets or contractor capabilities failing to perform as expected
- Organization/strategic risk - The risk arising from business decisions or implementation of those decisions. Strategic risk also incorporates how management analyzes external factors that affect the strategic direction of the business (e.g., corporate separation). Franchise or reputation risk is the organization impacts arising from changes in public opinion.
- Financial risk - The risk that the estimated cost of financing a business deviates significantly from original forecasts; includes the risk of loss resulting from inadequate interest rate and foreign exchange activity as well as the risk of loss from cash flow problems
- Legal - The risk arising from inconsistencies in contractual arrangements, resulting in contracts or arrangements not being enforceable
- Regulatory risk - The risk of loss from unexpected changes in local, federal, or state laws or market rules and procedures applicable to a certain region
- Political risk - External uncertainties that result from the actions of governments or other groups and the risks that internal organizational factors will limit the company's ability to effectively respond to these external uncertainties
- Technological risk - The risk of loss as it relates to the effect of new, more efficient systems that competitors may bring on line

These risks are addressed in supply contracts through a variety of provisions, as summarized below.

3.4 Managing a supply portfolio

The CCSF has substantial flexibility to bear CCA Program generation supply obligations and risks or assign them to a third party via contract. Within the context of its overall enterprise strategy, the CCSF will need to evaluate the various trade-offs between risks, prices, the administrative burden and required capabilities associated with supply management. In general, the CCSF can avoid many of the financial obligations and risks, while guiding the overall portfolio composition through the solicitation process. Or, the CCSF could actively engage in the supply management process by taking title to the power it purchases on behalf of residences and businesses.

A useful way to evaluate the supply management options available to the CCSF is to separate them in to three primary authorities the CCSF could contract for from an ESP. By contracting for these authorities, CCSF would be delegating authority for these functions to its selected ESP. However, these authorities can be contracted under rules and protocols that bound these authorities within limits established by CCSF or require approval for operation outside of established ranges.

- Authority to shape portfolio fuel mix/resource type
- Authority to shape purchasing practices and risk management policies
- Authority to manage counter party risk

3.5 Electricity supply agreements

For large power solicitations it is common practice to develop a supply agreement in conjunction with an RFP. The agreement may either be a draft document, subject to negotiation with winning bidders, or it could be a binding supply agreement. The purpose of the agreement is to specify risks and obligations and assign them to contractual parties. High levels of specificity in the supply agreement permit bidders to minimize premiums for unspecified risks. Full requirements supply agreements generally have numerous provisions and can be rather lengthy documents.

Given the nature of the supply market and the potential for market shifts that require expeditious responses from market participants, the supply agreement should identify the CCSF decision-making process and CCSF personnel with decision-making authority for resource decisions.

The remainder of Section 3 discusses various aspects of electricity supply agreements in competitive markets.

3.6 Procurement methods

The CCSF will have a variety of procurement options available to it. We summarize key potential dimensions of CCA Program procurement options below. These dimensions are not intended to be an exhaustive list, but do identify the primary dimensions for procurement.

Auctions vs. RFPs. The CCSF could select ESPs through either an auction or an RFP. Generally speaking, auctions lead to lower prices, but require specific and relatively simple product structures. It limits the ability of individual bidders to develop creative responses to the CCSF's needs. In contrast, RFPs generally allow more flexibility in responses but may lead to higher prices while offering higher levels of creativity by bidders relative to auctions.

Multiple v. Single Contract Awards. The CCSF could contract with multiple providers. In order to award multiple bidders with contracts a method for separating the full requirements load obligation must be determined and set forth in the RFP and supply contract. Several methods for separating the load obligation are summarized below: (Offer examples of where these approaches have been used.)

- **Tranches ("slice of system").** The CCSF could "vertically" divide the load obligation into tranches (sometimes called a "slice of system" product). Each tranche has the same load shape as the total load being auctioned. Prospective ESPs offer full requirements products to serve one or more tranches, with the winning ESPs being selected via an auction or RFP. This process could be used for total load or for the load of one or more classes.
- **Customer Classes.** The CCSF could divide the load obligation by different groups of customers, such as small customers and large customers or according to existing PG&E rate classes. Prospective ESPs offer full requirements products to serve one of more customer groups, with the winning ESPs being selected via an auction or RFP
- **Geographic Areas.** The CCSF could divide the load obligation by different geographic areas within the city. Prospective ESPs offer full requirements products to serve one of more regions, with the winning ESPs being selected via an auction or RFP
- **Generation Products.** The CCSF could divide the load obligation into generation products (baseload, peaking, wind, etc.) and assume responsibility for packaging the products together to provide full requirements service. Because the CCSF would take title to the power, this approach is treated separately below.

Wholesale Procurement v. Retail Procurement. Most of the discussion in this document assumes the CCSF will not take title to the electricity it is procuring on behalf of its residents and businesses. That is, prospective suppliers are Energy Service Providers responsible for meeting the load obligation of all Participating Consumers. The CCSF obligation is limited to a contract administrator and does not conduct Wholesale Procurement. Its role is to conduct Retail Procurement.

However, if the CCSF took on the role of full requirements provider and conducted Wholesale Procurement, it would likely divide its load obligation into "horizontal" segments either by product type (e.g., 7x24, 5x16, etc.), by resource characteristic (e.g., baseload, intermediate, peaking) and/or fuel mix (e.g. renewable, hydroelectric, fossil. It would seek wholesale suppliers for each segment. Winning ESPs could be selected based on segment auctions or based on an RFP process. Taking title to power would present an expanded set of obligations and risks for the CCSF.

The particular method of procurement will vary based on customer requirements and restrictions. The table below summarizes specific solicitations and varying procurement methods used.

3.7 Retail rate – contract price relationship

A critical issue under a CCA Program is how the CCSF addresses the relationship between the prices it pays to procure power and the prices it charges to its residents and businesses for retail generation service. There are three general categories for setting retail prices under a variety of wholesale price setting mechanisms.

1. ESP direct pricing: The ESP contract price (including commodity, attribute, services and administration) is the same as the price charged to end-users. The solicitation would request bids for retail prices according to a specified customer classification (e.g. PG&E rate class).[2]
2. ESP indirect pricing: ESP contract price is not the same as the price charged to end-users. A price conversion and revenue reconciliation would be required to "translate" ESP bid prices to retail rates and accurately pay the ESP according to its bid price.
3. CCSF pricing: CCSF acts as the ESP because it takes title to wholesale supply. Retail rates are set according to CCSF procurement and rate setting function.

The specific approach taken will raise a host of contractual issues that are likely to have an impact on the market response to the CCSF solicitation. One issue under ESP indirect pricing is the need to specify the approach taken to reconcile contract prices with retail rates. . Another issue will be any rate equity impacts under each approach. AB 117 requires that the CCSF will provide "equitable treatment of all classes of customers," although the specific rate-related standard for this treatment is not specified in the statute. Another issue is the ability to structure retail prices to account for underlying variations in cost (e.g. seasonal or time-of-day variations).

Finally, between options 1 and 2 there is an expected trade-off between retail rate transparency and inflexible bidding. That is, ESP direct pricing has a more transparent relationship between retail rates and contracted price. However, requiring ESPs to bid according to PG&E's rate classes is almost certain to lead to higher prices than bid structures that are designed to create the lowest full requirements price. (Also an interaction with number of products offered – all wind, solar for the future, etc.)

Retail pricing structures under a CCA Program can be classified into four general categories: - as further discussed in Chapter 3.

- Percent increase or discount off PG&E tariff rates – generation service rates are set in comparison to PG&E rates. All Participating Customers within a PG&E rate class pay the same rate.
- Customer class pricing – rates are set for each customer class. All Participating Customers within a class pay the same rate.
- Customer class plus custom pricing - rates are set for each customer class, except certain customers (i.e. very large energy buyers). All Participating Customers within a customer class pay the same rate, while certain customers receive custom pricing and contracts.
- Various indirect mechanisms – the CCSF could provide a mix of generation services (e.g. volume at various pricing structures (see Table 1 for pricing types)

3.8 Examples of procurement and pricing approaches

[2] ESP direct pricing appears to be contemplated as an option in Ordinance 0086-04. However, such a method may not meet the transparent ratesetting process requirements of AB 117.

To demonstrate the wide variety of approaches taken in US competitive electric markets, Table 2 summarizes aggregation and municipal energy purchasing structures.

Table 3. Examples of aggregation programs and municipal power purchasing

Soliciting Organization	Procurement Method and Pricing Structure
New Jersey Utilities	Annual "descending clock" auction for full requirements service purchased by utility and provided by multiple bidders. Utility retail prices are set via formula that converts auction prices. Two concurrent auctions conducted: large customer auction (hourly energy prices) and small customer auction (fixed prices). Fixed price auction has tiered terms from 1 year to 3 years.
City of Baltimore Purchasing Pool	RFP for aggregated municipal accounts – bid prices are made for each rate class in the form of discounted price from utility service. Prices can be flat or tiered. Accounts that would result in a higher price may be removed from the bid at the City's discretion. Individual accounts/agencies in the group must sign a contract with ESP. The contract term is for 18 or 30 months.
NOPEC (Ohio) opt out municipal aggregation group	NOPEC, a regional council governed by a General Assembly made up of one representative from each community, "bands" municipalities together for combined energy purchases via periodic RFPs. Customers receive a fixed percent discount off utility rate (currently residential and municipal is 6% and commercial is 4%). Each municipality must provide written notice (9 months in advance, in one case) to NOPEC if they intend to leave the program. The contract term is 6 years. Customers can opt out every two years without paying a fee, otherwise they pay $25. The local utility issues bills for ESP. ESP, not NOPEC, performs customer service functions.
Texas General Land Office	Through an RFP process GLO administers its State Power Program that purchases electricity and gas on behalf of state and local governments and schools. Primary role of GLO is to manage mineral and fossil fuel rights on state land and collect rents and royalties. State law allows GLO to take its gas royalties in kind, trade them for electricity, and sell that electricity to state and local agencies. GLO contracts with ESPs for all energy-related, including physical and financial aspects of converting royalties taken "in-kind" to electricity, retail marketing, sales, billing, etc. Proceeds go to Available School Fund (property tax relief). GLO has about 330 customers serving over 10,000 locations and 800 MW.
Cape Light Compact (Massachusetts)	Inter-government al organization governed by member towns. Procured power under opt out program through RFP on behalf of 21 towns with 196,000 customers on Cape Cod. A single price was provided to all customers, although adjustments were made at set dates. No fees are charged for customers that leave program. Green power option available on a voluntary basis. Program also includes REC purchases. Compact, not ESP, notified customers, but paid by ESP. Initial contract term was 2 and half years. New ESP has 1-year contract.
GSA (Federal Government)	Online "reverse auction" is used in which ESPs bid on GSA's energy requirements to arrive at lowest price. Prices are either fixed for all customers within a geographic area or are set by customer groups. GSA solicitations have requested bids for varying levels of renewable energy content. GSA acts as a procurement agent and contract administrator on behalf of government agencies and facilities. Contract terms vary between 12 and 36 months
Maryland utilities	Annual multi-stage RFP for full requirements supply awarded to multiple bidders for multiple customer classes (defined by peak load). Utility provides retail service at fixed rates, while suppliers provide a specific percentage of retail load defined as tranches.

3.9 Load Serving Entity

As defined earlier, a Load Serving Entity (LSE) is an organization authorized or required to supply electricity to retail customers located within a particular electrical system (e.g. California ISO). An LSE's obligation is to ensure the purchase and delivery of energy, capacity, ancillary services, transmission services and other components of full requirements supply on behalf of its retail consumers. In California, the physical operating requirements of LSE's must be met through a Scheduling Coordinator, which may or may not be the same organization as the LSE. An LSE is either a regulated utility, an ESP or possibly the CCSF. Under a CCA Program the question arises: whom is the load serving entity?

Under a CCA Program, the CCSF would be defined as the "Community Choice Aggregator" under AB 117 (California Utilities Code, 331.1). According to AB 117, "A community choice aggregator may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers. The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services." (California Utilities Code, 366.2(c)(1))

Under a full requirements supply contract, the ESP would likely take on the LSE obligation under a contract with the CCSF. If this is the likely scenario for the CCSF, several questions arise:

- What financial obligations and liabilities does the CCSF have in the event the ESP defaults or breach of contract?
- What obligations does the CCSF have to meet California ISO, PG&E and end use customer requirements for providing electricity generation service in the event the ESP defaults or breach of contract?
- What obligations does the CCSF have to meet PG&E's operational and financial (and/or service agreement) requirements in the event the ESP defaults or breach of contract?

These issues will need to be addressed in an ESP contract, as well as CCSF-PG&E service agreement. CCSF anticipates that service agreement details between PG&E and CCAs will be addressed in the CPUC CCA Phase 2 proceeding.

3.10 Opt out, direct access and returning/new customers

Through its supply contract and directly with customers, the CCSF will need to manage the risk of customers leaving the CCA Program and going to Direct Access or Bundled service with PG&E. It must also address contractual obligations for customers that seek to return to CCSF service or that are new residents and businesses in the city.

Leave CCA Program. The primary methods for addressing customers that leave the CCA Program and purchase generation service from either PG&E or through Direct Access are:

- Exit fee – charge customers a set fee or fee based on formula for leaving CCA Program outside of opt out periods
- Minimum stay – After opt out period expires, Participating Customers must stay with the CCA Program for a minimum amount of time
- No restrictions or penalties – Participating Customers can leave the CCA Program at will – creates volumetric risk for the ESP, placing upward pressure on price
- Opt out periods – establish periodic dates when customers can opt out without penalty

Customers that leave the CCA Program and return to PG&E may also be subject to switching rules related to tariffs available for customers returning to PG&E. The CPUC CCA Phase 2 proceeding will address issues related to CCA customer switching.

Return to CCA Program. The primary methods for addressing customers that return to the CCA Program from either PG&E or Direct Access are:

- No change in price, service or terms – Participating Customers may purchase power at the same price and terms as existing customers. Depending upon customer size this may be a substantial risk to an ESP.
- Not allowed or limited enrollment – PG&E and DA customers cannot join the CCA Program or they may join but only during certain enrollment periods.
- Reprice or new price – Customer that return receive a different price than initial solicitation price, which may be less favorable than existing Participating Customers.
- Minimum stay – Customers that return to the CCA Program could be required to remain a customer for some minimum time period.

3.11 Load changes during contract

A supply agreement is likely to include a provision that specifies the rights and responsibilities of the ESP when material changes to load occurs, such as a significant change in economic conditions. In the event of a significant change in contract load, the CCSF may agree, if requested by the ESP, to negotiate in good faith to equitably adjust contract pricing so that the ESP is made whole. Adjustments to contract pricing would compare contract price with the market price at the time of usage deviation to arrive at an adjustment to contract pricing. The contract would specify thresholds that define material changes in contracted load.

Examples: GSA's Nimo Solicitation

3.12 Exclusivity or non-compete provisions

The CCSF would likely need to establish an exclusivity or non-compete provision to prohibit CCA Program ESPs from supplying customers in the CCSF boundaries with service under a Direct Access contract. Such provisions would have to take into consideration existing DA supply contracts, including those that allow for new facilities to be added to an existing contract.

3.13 Term of contract

The term of the CCA Program contract will be a significant factor in soliciting attractive bids. Long terms contracts are attractive to ESPs, as long as their supply obligation can be effectively hedged. The CCSF will also benefit by through a long-term contract, relative to short term, by avoiding transaction costs and other contract initiation efforts. Long term contracts for competitive retail electricity supply is defined as 4 years or more. There are numerous options for structuring the contract to both ensure a long-term relationship between the CCSF and ESP(s) and ensure the high risk premiums associated with long term contracts are mitigated.

Contracts can be structured so pricing adjustments can be made periodically, perhaps annually or every two years (however retail rates may need to change more frequently – see Chapter 3). The CCSF could provide a specific price adjustment structure or bidders would provide their own structure. Changes in the prices could be based on inflation indexes, fuel/power cost adjustments, changes in CRS levels, etc. If a specific structure (e.g. index) is not desired by the parties, a provision that states that prices will be adjusted via negotiation could be adopted. Either approach would allow for a long-term commitment by both parties while providing for price adjustments.

In addition to price adjustments, the CCSF may seek to provide adjustments to generation mix or renewable content from time to time e.g. if CCSF enters into bond financing arrangement for the purchase of renewable power. Similar provisions for adjustments can be created. This would allow the CCSF to increase renewable resource consumption based on changes in market conditions or CCSF objectives while maintaining a long-term contractual commitment to ESP(s).

Extension provisions could also be included in the contract which allow for the CCSF to extend the existing contract price and terms as long as they are favorable to the CCSF and the ESP is willing to offer

Long term contract examples: NOPEC RFP

3.14 ESP default and remedies

There are several types of ESP default under a CCA Program:

- Non-Payment
- Failure to perform
- Misrepresentation
- Bankruptcy
- Criminal or unethical behavior

Provisions to address possible ESP default are required in the contract, including a termination for default provision and a remedy to insure the CCSF is not harmed by the

default. Credit and financial assurance provisions as described below are also key provisions to address ESP default.

3.15 Credit and financial assurance

The CCSF will need to establish credit and financial assurance policies and procedures that protect it in the event a CCA Program Counter Party fails to meet its obligations. The policies and requirements imposed upon third parties by the CCSF will need to be specified in the supply contract or in a separate credit agreement.

These policies are likely to result in specific contractual provisions and related CCSF responsibilities. The primary responsibilities can be categorized as follows:

- credit application and creditworthiness process
- security process
- creditworthiness monitoring process
- credit policy evaluation process

The CCSF will need to adopt specific provisions in the supply/credit agreement that both protect it from credit exposure and encourage a large number of bidders. Balancing these often opposing objectives will require a specific strategy and set of policies. Common credit provisions are listed below.

- Termination payment provisions (liquidated damages) – in the case of default, provides the CCSF with compensation for the underlying value of the contract. Commonly calculated by taking the discounted present value of the positive or negative difference obtained by subtracting the value of a replacement contract from the existing contract.
- Step up provisions (under a multiple provider CCA Program) – in the case of default by an ESP, other contracted ESPs take on the defaulting parties' supply obligation usually by offering an option, not an obligation to the non-defaulting parties.
- Credit threshold and credit limit provisions – based on credit policies, there will be varied requirements for establishing and managing credit of ESPs under a CCA Program.
- Mark to Market credit exposure calculation – credit exposure is commonly measured through mark to market calculations that made daily or weekly based on market prices of electricity. These provisions require the ESP to post security according to the value of the contract. Credit exposure calculations commonly have margin call provisions as well, which specify the terms and conditions that a counter party obtains security from an ESP when it exceeds credit thresholds.

Credit Policy Examples: EEI Purchase and Sales Agreement, New Jersey BGS Credit Supplier Master Agreement

3.16 Relationship between credit and power prices

Credit has become a significant burden for some prospective ESPs to contract with wholesale generation providers and ISOs. The CCSF could potentially reduce its overall price, if it pledged its full faith and credit on behalf of an ESP. This is an issue to further investigate.

3.17 Termination for convenience provisions

Termination for convenience provisions are common in municipal government contracts, but present potentially substantial risk to ESPs. These provisions provide the right to terminate the contractor's performance without the government being liable for breach-of-contract damages.

Examples: City of Baltimore Invitation for Bids

In addition to these general credit concerns, AB 117 also imposes a specific deposit requirement upon CCA and the proposed language of the RFP in Ordinance 0086-04 mirrors this language in stating that "qualifying Electric Service Providers post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E ...." (Section 4-G). This requirement is likely to be met by any credit-worthy ESP – given, however the potentially very large number of customers and amount of load served by the ESP – it may be this requirement will increase the insurance requirements of an ESP – a cost likely to be passed on to the CCA.

4. SUPPORTING SERVICES

4.1 Functional responsibilities

In addition to the physical and financial components of full requirements electricity supply described above, several additional functional responsibilities will be part of the CCA Program. These are supporting services for the CCSF-ESP supply contract. A potential list of primary functional responsibilities across both the ESP and CCSF are listed below: (Cross-check with final SG)

- Communications, sales & marketing
- Load forecasting
- Resource planning
- Service liaison with PG&E
- Rate setting
- Customer care
- Legal
- Regulatory affairs

- Settlement and billing

Chapter 7 examines the organizational options for CCA. That chapter incorporates considerations regarding CCSF itself undertaking a number of the above responsibilities.

But here wee address the contracting options for those functions that are potentially suitable for the CCSF to contract with a third party, either an ESP or another entity.

4.2 Communications, sales & marketing (CSM)

There is a wide array of options available to the CCSF for CSM-related contracting. It is assumed that the CCSF will have overall responsibility for CSM under the CCA Program, but there are likely to be ESP responsibilities that would need to be addressed in an agreement. Responsibilities might include funding or partial funding of opt out notification and education initiatives, administration of key account programs, joint marketing efforts, etc.

4.3 Load forecasting

Short Term Forecasts:
Accurate short-term load forecasts are essential to minimizing the Volumetric Risk described earlier. Such forecasts provide the target for the ESP to supply power on an hourly, daily and monthly basis. If the ESP is responsible for the volumetric risk, it is in the ESP's self interest to have the most accurate short-term forecasts possible and then matching supplies to those forecasts.

The costs associated with the volumetric risk are directly related to how well the supplies met the loads on an hourly basis throughout the time period. How well supplies meet demands is discovered in the Settlement Process. Knowing the hourly supplies provided by the ESP will be easy. Knowing the total hourly loads in the CCSF territory is more problematic. The hourly loads will be the sum of the parts, i.e., the total hourly loads of all the customer classes in the city. Most CCA Programs, and especially large ones such as CCSF's would have all customer classes represented.

Larger customers will have sophisticated time interval meters and their hourly load will be known after the fact during the settlement process. Many of those meters will have communication lines installed allowing the loads to be monitored in real time.

For Smaller customers such as residential and small commercial, PG&E and other utilities use dynamic load profiling for settlement purposes. Dynamic load profiling is done by the utilities on a daily basis and it requires that previously established load research sample meters be read, these data validated and load profiles produced for the customer class each day. This is a real time construction of a load shape and it captures all of the factors (e.g., weather) that drive the shape of the load profile. Given, however the flatter load profile for San Francisco customers the costs/benefits of calculating a San Francisco specific load profile should be examined. Costs might include the need to

install more load research meters on customers and arrange with PG&E for real-time access to the load research data. Benefits would include potentially significant reductions in power contracting costs – including resource adequacy requirements, and properly tracking the impacts of energy efficiency and demand reduction programs. While the CCA Phase 1 CPUC decision has ruled out the option of using a San Francisco specific load profile, for now, this part of the decision may undergo reconsideration and, as shown in Chapter 4, using a San Francisco specific load profile is likely to lead to substantial cost savings over time.

<u>Intermediate Term Forecasts – And Long Term Forecasts</u>
Successful Resource Planning (see the next function) will require accurate intermediate and long-term load forecasts. The ESP will be held accountable to meet certain cost and reliability standards in its resource plan and that will give it a vested self-interest to prepare and use the best estimates of actual needs in the intermediate and long term.

<u>Options to delegating Responsibility for Load Forecasting to the ESP</u>
If the CCSF decides to use multiple ESPs or for other reasons decides not to delegate Load forecasting responsibilities to its ESP, what options are there to accomplish this function?

For short term load forecasting, there are two options:

- Perform Load Forecasting internally by CCSF staff
- Contract with another 3rd party to perform Load Forecasting

In either case, the short-term load forecasting function would need to be a daily (365/year) activity and would require EDI connections with PG&E and with ESPs. Contract(s) with ESP(s) would need to require that it (they) would be responsible to meet the forecasts and would specify which party would be responsible for actual load deviations from the forecasts.

The same two options exist for the intermediate and long term load forecasting. In this case, the function would be performed periodically with updates as required. This effort would inform the Resource Planning function, which itself could be performed by internal staff or be contracted to others. The key to success will be assuring timely and accurate communications between the forecasting and planning functions and clear delineation of responsibilities.

4.4 <u>Settlement and billing</u>

As required by AB 117, PG&E will be responsible for providing all metering, billing, collection and customer service to retail customers that participate in community choice aggregation programs. Retail customers will pay PG&E for generation relates service and PG&E will in turn pay the CCSF or the ESP for those services. Consequently, PG&E could provide billing determinant data, payment and collections data to either the CCSF or the ESP or both.

The ESP will need to have customer usage data for settlement purposes and will need to deal with the data interfaces with PG&E to do so. Customer service functions will need real time access to these usage data and billing and payment data also to answer customer inquiries, manage customer non-payment issues, etc. Most potential ESPs are already set up to interface with PG&E and to perform these data management data access functions. Here as elsewhere, the contract with the ESP would need to specifically spell out the type of data and the type of access needed by CCSF to those data.

There are five key payment processes that must be addressed in the contract:

- Profiling and settlement data (billing determinants) management
- Billing data management
- Accounts receivable management
- Payment processing
- Collections processing

The CCSF will likely need to establish an ESP(s) and PG&E auditing function. Consequently, service agreements with both ESP(s) and PG&E will need to specify the authority and process for auditing appropriate transaction data of the CCA Program.

4.5 Resource planning in compliance with requirements set by others

The resources used to meet the CCSF's loads must meet several criteria including operational criteria, economic criteria and energy source (Clean, Green, Renewable, RPS eligible, Green-e or EPA GPP eligible, etc.). These criteria are set by several parties including the ISO, AB 117, the CPUC, other regulatory bodies and by CCSF itself as a matter of policy and ordinance. In the long term, this may include city owned facilities, energy efficiency programs and other sources not contemplated now.

The contract would need to be specific on what these criteria are and how changes in the criteria would be handled, etc.

4.6 Options for Delegating Responsibility for Resource Planning to the ESP

It would be difficult, and even counterproductive to assign this function to a party other than the ESP, however, if the CCSF decides to use multiple ESPs or for other reasons decides not to delegate Resource Planning responsibilities to its ESP, what options are there to accomplish this function?

As before, there are two options:

- Perform Resource Planning internally by CCSF staff
- Contract with another 3rd party to perform Resource Planning

The issues would be the tendency of the resource planning party to over manage the ESP and in doing so, drive up costs. The resource plan would have to balance the policy requirements with the operational criteria as discussed above. This balance may be more

easily reached with the planning function done internally than with it done by a third party. Any third party contract would have to be carefully designed to provide the correct incentives for the third party to reach the proper balance.

5. RENEWABLE RESOURCE DEVELOPMENT AND SUPPLY

Given stated objectives of the CCSF to further develop renewable production resources, this section summarizes the options available to the CCSF, in the context of a CCA Program, for increasing the use of renewable resources, through both consumption and production.

5.1 Buying versus producing renewable energy

Under a CCA Program, the CCSF could act as a buyer and/or a producer of renewable energy. Through a separate solicitation process, the CCSF could either (1) contract for renewable generation service and its attributes (i.e. RECs), (2) contract for renewable attributes only and/or (3) contract for the design and construction of renewable generation facilities that the CCSF would finance and own. Given these three primary options, we summarize various solicitation-related options available to the CCSF.

5.2 Solicitation process

Under any of the three options above, the solicitation process will require an RFP and perhaps a sample contract. The solicitation will define the resource mix over time and the level of flexibility regarding renewables delivery as described above. The solicitation will require various forms and documentation, such as offer forms, credit information and agreements, facility information form and pricing form. The CCSF will need to develop a solicitation website and develop tactics similar to those highlighted in the energy supply solicitation described earlier.

The RFP will need to address the following key issues:

- MW or MWh goals
- Contract term
- Schedule and approval process (SFBOS, CPUC, etc.)
- Credit terms
- Binding nature of offers
- REC ownership
- REC attributes (e.g. vintage,
- Production tax credit assumptions
- Selection criteria – price/market value, environmental objectives, other non-price factors

5.3 Options for development and operation of renewable resources

Should the CCSF desire to own renewable generation resources, we assume the CCSF will contract with a developer and operator, rather than perform those functions itself. Consequently, a solicitation(s) and contract(s) will need to developed and managed separately from any energy/REC supply and purchase agreements.

An operating agreement may be a separate solicitation or part of a single design, build, and operate solicitation. Either way, the RFP, bond issuance,[3] and sample contract will need to address the following key issues related to an operating agreement:

- Capacity/Quantity
- Availability
- Transmission impacts
- Types of products:
  - As-Available – intermittent energy not controlled by the operator
  - Baseload – power available 7 x 24 at a high capacity factor (over 70%)
  - Peaking – power available 5 x 8 during summer or winter peak periods
  - Dispatchable – power available on a day ahead or intra-day basis during summer months
  - Acquisition of shaping products on the wholesale market so as to gain the best possible advantage from intermittent renewable generation.

5.4 <u>Qualifying and selecting renewable projects</u>

For investing in renewable generation projects, CCSF will need to specify the qualifications and requirements for which bidders must comply. The following list identifies likely provisions for qualifying bids:

- Eligible Technology
- Eligible Fuel
- RPS Eligibility
- Permitting, Licensing and other authorizations
- New facilities v. existing facilities
- Eligible Location
- Eligible Ownership
- Permitting Compliance
- Timeline Compliance
- Dispatch Eligibility
- Vendor experience
- Project economics
- Eligibility for supplemental energy payments under New Renewable Facilities Program
- Eligibility for other grants and incentives

[3] See Chapter 5

For a renewable energy or renewable attribute purchase and sales contract, the key requirements are similar to full requirements electricity supply discussed in the prior sections, with the following differences/additions:

- Renewable energy specification
- REC specification
- REC documentation
- Third party auditor or verification process for RECs

5.5 Sale/transfer of output

As an owner of renewable production resources, the CCSF will need to arrange for the sale or transfer of the output to the ESP(s) responsible for the CCA Program. Numerous issues will need to be addressed in the CCA Program contract or separately to address the treatment of CCSF renewable production, including:

- Will there be a separate purchase and sales agreement or part of CCA Program contract?
- Will the ESP take title to power or will its role be limited to scheduling and related functions?
- How will retail prices charged by the ESP be impacted by CCSF produced energy?
- What quantity specifications and stipulations will be required for the ESP to manage the output for Participating Customers?
- Beyond quantity requirements, what contractual relationships related to CCSF production will there be in full requirements supply agreement(s)?
- Will the CCSF sell its production outside of the CCA Program? If so, under what conditions and under what solicitation processes?

6. GLOSSARY

Derivative: A derivative is a transaction that is designed to create price exposure, and thereby transfer risk, by having its value determined – or derived – from the value of an underlying commodity, security, index, rate or event. Unlike stocks, bonds and bank loans, derivatives generally do not involve the transfer of a title or principle, and thus can be thought of as creating pure price exposure, by linking their value to a notional amount or principle of the underlying item

Ancillary Services: Necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Electric Service Provider (ESP): An entity that provides electric service to a retail or end-use customer.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Scheduling Coordinators: Entities certified by the Federal Energy Regulatory Commission that act as a go-between with the Independent System Operator on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule the distribution of electricity.

Load Serving Entity (LSE) - a class of organizations authorized or required to supply electricity to retail customers located within a particular electrical system.

Full Requirements Electricity Agreement – a purchase and sale agreement for electricity generation service provided to retail end use customers. The generation service bundles together the various wholesale generation and grid services to serve retail customers.

Volumetric Risk - the inability of sellers to precisely match the actual volumes consumed by their customers with the forecasted volumes, leaving the seller exposed to the purchase of electricity (and sale of excess) at a variable price while selling to customers at a fixed price. This includes load shaping risk, migration risk, weather risk, forecasting error risk and weather risk.

Participating Customers - Customers served under the CCA Program

Direct Access Customers – Customers served by ESPs in the competitive retail market

Opt Out Customers – Customers that opt out of the CCA Program and are served by PG&E under a bundled service

Utility Service Agreement (USA) – CCSF or ESP agreement with PG&E

CCA Program – Community Choice Aggregation Program

CRS - Cost Responsibility Surcharge

Renewable Energy Credit ("REC") - A generic term for a bundle of attributes that does not include the actual electrical energy associated with the generation of electricity at a renewable energy facility. Depending upon the facility, the REC will embody various attributes with varying quantitative values. Values – such as avoided emissions – are

quantified according to some baseline metric, engineering estimate, or a value deemed by private or government bodies. (Center for Resource Solutions)

7. APPENDIX: LIST OF RFPs AND SAMPLE CONTRACTS

KEMA has compiled sample solicitations and contracts for various types of electricity generation service transactions. The full set of documents will be made available electronically at the time the final draft report is delivered. We expect to add more solicitation samples between the first and final draft. The list below identifies the current inventory of sample RFPs and Contracts.

Organization	Type of Document
AEP (SPP)	RFP for 250 MW of renewable resources
Allegheny Power (Maryland SOS)	Full requirements supply agreement, RFP
AllEnergy and Essential.com	Reseller Contract
Avista Energy	Wind RFP
Cape Light Compact	Supply Contract
City of Aurura, OH (OH aggregaton)	Municipal Aggregation RFP
City of Baltimore	Soliciation
City of Green, OH (OH aggregaton)	Municipal Aggregation RFP
City of Munroe Falls, OH (OH aggregaton)	Municipal Aggregation RFP
City of Stow, OH (OH aggregaton)	Municipal Aggregation RFP
Connecticut utilities	RFP, Service Agreeents for default generation service
Detroit Edison Renewable Program	RFP
EEI	Master Purchasae & Sales Agreement; Master Netting Agreement
Federal GSA	Solicitations: New England (gas), NIMO (power), Mid-Atlantic (RECs)
LADWP renewable supply	RFP, contract, forms, presentation, etc.
LIPA Biogas Microturbine	RFP, Contract Template
Miami Valley Communications Council (OH aggregaton)	Municipal Aggregation RFP
Minnesota Power (supply resources)	RFP, Draft Agreement
Mirant and ECONnergy	Wholesale contract
New Jersey BGS (CIEP)	Master Supply Agreement, Credit Agreement
New Jersey BGS (FP)	Master Supply Agreement, Credit Agreement
New Jersey Renewable Program (Distributed Renewables)	Solicitations: Distributed Resources, Economic Development
NOPEC	Municipal Aggregation RFP
NYSERDA (Wind generation)	RFI, response format
Ontario Energy Board	Clean Energy Supply RFP and Contract, Demand Response Contract
Pacificorp Renewables Solicitation	RFP, Contract , presentation
PG&E Renewables RFP	RFP, contract, forms, presentation, etc.
PG&E Long Term Supply RFO	RFP, contract, forms, presentation, etc.
Rhode Island Renewable Incentive Program	RFP
Roseville Electric Green Energy Program	RFP
SDG&E Renewables RFP	RFP, contract, forms, presentation, etc.
Sierra Pacific Renewable RFP	RFP, Contract Template
SMUD Renewables Solicitation ("Ownership Options")	RFP, Contract Template
SMUD Wind Solicitation	RFP, Contract Template
Southern California Edison (Generation supply)	RFO package
Texas General Land Office	Sales Agreement
TXU Sesco	Wholesale supply RFP and contract
University of Michigan	Electicity supply RFP
Village of Silver Lake, OH (OH aggregaton)	Aggregation RFP
WAPA (RECs)	RFP

Community Choice Aggregation Draft Implementation Plan

Chapter 7 Organizational Scenarios

Prepared
With
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Table of Contents

1. INTRODUCTION - PG&E and CCA FUNCTIONAL RESPONSIBILITY

This chapter examines the organizational options available to the city as it considers the CCA decision. Here the key decision revolves around the range and degree of CCA functions to be undertaken by city employees and the location of those employees' e.g. existing city agencies or an entirely new CCA agency.

By law, certain functions must continue to be performed by the investor-owned utilities now serving those communities contemplating Community Choice Aggregation. These functions include:

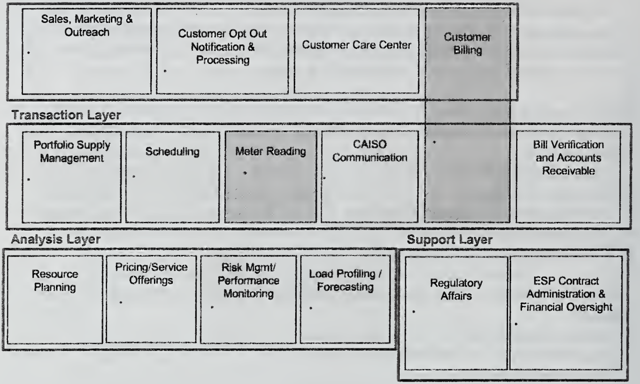
- Meter Reading,
- Customer Billing,
- Retail Customer Payment Collection,
- Customer Service Related to PG&E Functions, and
- Maintenance and Investment in the Power Distribution System.

Those functions that a <u>CCA</u> is expected to undertake (itself or through outsourcing) include:

- Sales & Marketing
- Customer Opt Out Notification and Processing
- Customer Care
- Electricity Portfolio Supply and Management
- Power Delivery Scheduling
- Communication/Coordination with the California Independent System Operator
- Power Resource and/or supplier Contract Administration and Financial Oversight
- Load Profiling and Forecasting
- Product and Service Offerings and Pricing, including energy efficiency programs
- Cost/Revenue/Profitability Analysis
- Risk Management
- (Wholesale and Retail) Bill Verification and Accounts Receivable
- Regulatory Affairs

A visual breakout of these various functions is shown below.

MANDATORY IOU AND POTENTIAL CCA AND ESP FUNCTIONS



2. POTENTIAL CCA ORGANIZATIONAL APPROACHES

Four alternative organizational approaches from which the city may choose are listed below. The approaches reflect a continuum for the degree of internalized versus contracted execution of CCA functions. The range includes:

- Contract for all functions. An example is the towing service for illegally parked cars.
- Contract for most functions, with the exception of certain discrete items that the City may want to perform itself. The city does this e.g. for janitorial services at San Francisco airport, and for solid waste collection.
- Contract for some discrete, specialty functions, while the City performs functions core to the public face of its CCA mission. For example the SFPUC contracts for some specialized functions relating to water and sewer service.
- City performs all functions, operating more akin to a publicly owned utility that is limited to responsibility for power supply and customer care functions.

In an approach where city employees perform different functions, Appendix A addresses the potential organizational structure, staffing and salary cost of the potential city functions.
An important point to note is that staffing of various functions by city employees will not necessarily result in a dollar for dollar savings in the costs charged by a supplier. Due to

the economies of scope and scale possessed by many suppliers it may be that city staffing of various supplier related functions results in only a partial dollar savings.

2.1 Should the CCA Contract for All Functions?

A good example of this is the Cape Light Compact in Massachusetts. This compact is a consortium of 21 towns and 2 counties in Massachusetts, buying power on behalf of 197,000 customers. The served load is 410 MW now, expected to grow to 600 MW. Cape Light has only six staff, primarily responsible for issuing and managing contracts with an energy services provider (ESP) and a series of organizations delivering energy efficiency services. The ESP handles all customer interface and ratemaking. However the Compact retains the overall policy direction for the supplier portfolio and for setting energy efficiency goals.

2.2 Should the CCA Contract for Most Functions?

In this case, the city would retain performance of only certain discrete items. These items might include public communications, "customer contact", some form of auditing of the power resource contract settlements of the supplier, and ultimate rate design authority. This model might be similar to the city approach to solid waste collection and recycling, where private waste haulers perform the majority of activities, while the City carries out public communications, supports recycling efforts, and manages the waste haulers' contracts. Again the overall policy direction regarding the supplier portfolio – including potentially energy efficiency efforts would be undertaken by the City.

2.3 Should the CCA Contract for Some Discrete, Specialty Functions?

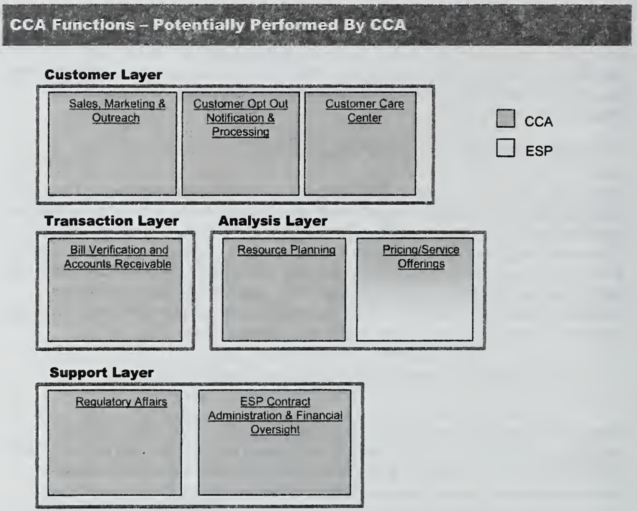
Here the city functions most likely would relate to the CCA's fiduciary role, public visibility as the "face" of CCA in San Francisco for all public interaction including sales and marketing to CCA customers, and an on-going regulatory monitoring and intervention strategy at the State and Federal level to protect the CCA interest. In this case e.g. CCA customers would have billing problems dealt with via a CCA call centre that would have ready access to a customer information system holding customer-billing data. However all the specialized aspects of power operation – e.g. load forecasting, wholesale power purchasing, portfolio construction and operation, and scheduling and settlement of power with the ISO could be the functions contracted to an ESP or other type of supplier. Under this more hands-on organizational form the city could expect the CCA to have frequent interaction with the supplier regarding overall portfolio construction.

2.4 Should the City Perform All CCA Functions?

Examples of this approach include the cities of Palo Alto and Santa Clara (with its Silicon Valley Power), the Sacramento Municipal Utility District (a special purpose public district organization), and the City of Austin, Texas (Austin Energy). The only

difference in the case of a CCA is that the investor-owned utility owns and maintains the power (or gas) distribution system, not the local community.

The figure below shows the potential range of activities that could be undertaken by the City in a substantial CCA role.



2.5 Comparing Potential CCA Business Models

Table 1 provides comparisons for different kinds of community electric service being offered today. Note that the some of the distribution utilities own generation assets directly or in percentage shares through joint powers authorities. All of the municipal utilities own their local power distribution systems.

Table 1. Examples of Community Electric Service

Organization	**Peak MW Demand**	**Sales (GWh)**	**# Accounts**	**# Employees**	**Organization**
San Francisco CCA	700-850MW (no opt-out, no municipal load or direct access load))	Currently About 4000	354,000	To Be Decided	CCA
Cape Light Compact, Massachusetts	410 MW Summer, 343 MW Winter. Forecast of 600 MW	1911	197,000 across 21 towns and 2 counties	6: contracted ESP (ConEdison Solutions) and 11 EE service providers	Municipal Aggregation
Northeast Ohio Public Energy Council (NOPEC)	1000MW	3000	Serving approx. 455,000 residential customers with potential for 600,000 from 110 communities	No full-time employees Eight Person Board of Directors.	Municipal Aggregation
ABAG Green Power (Association of Bay Area Governments)				Serves member cities and counties *municipal loads only*	Direct Access Aggregation
Palo Alto Utilities, City of Palo Alto	184	1000	[28,500 accounts.	124	Municipal Utility
Silicon Valley Power, City of Santa Clara	407	2,500	48,000	123	Municipal Utility
Sacramento Municipal Utility District (SMUD)	2800	9,920	553,000	2166	Municipal Utility

Table 2 below illustrates the benefits and risks of the different organizational approaches outlined previously. In all cases, the actual cost benefit or risk associated with electric supply will remain unknown until a contract is completed with a supplier.

Table 2. Organizational Approach Benefits and Risks

Organizational Choices	Benefits	Risks
Contract for all functions	▪ Economies of scale and scope with supplier providing specialized services amortized over multi-client base. ▪ Faster more streamlined start-up.	▪ Lose unique SF public face. ▪ May lose some flexibility for timely changes to the resource portfolio after contract is signed.
Contract for most functions, except discrete items	▪ Enables the city to select "public face" roles. ▪ Flexibility to adapt organization and operations to evolving fit of customers, and to work through early-year coordination logistics with PG&E.	▪ Potential delay in CCA start-up due to staffing needs ▪ May still lose some flexibility for changes to the resource portfolio after the contract is signed.
Contract for discrete specialty functions; City performs most others	▪ Keeps SF on path to more local control, local jobs. ▪ Can still contract for risk and complexity of power resource procurement. ▪ Retains greater local input into overall power resource mix, including development & delivery of EE & DG appropriate to community.	▪ Potential delay to CCA start-up due to the need to hire expert staff. ▪ Overall performance risks of city taking on new tasks. ▪ Need to coordinate with purchases of computer hardware and software to handle the various CCA functions. ▪ Potential coordination problems with supplier due to data sharing.
City performs all functions	▪ Provides the city complete independence as a CCA that assures any profits from CCA remain with the city.	▪ Greater financial risk of ensuring reliable, affordable power, without incurring CCA losses and/or a fallback to General Fund. ▪ Potential delay in CCA start-up due to the need to hire the greatest number of expert staff. ▪ Overall performance risks of city taking on new tasks. ▪ Need to coordinate with purchases of computer hardware and software to handle the various CCA functions.

3. THE CCSF ORGANIZATIONAL DECISION CONTEXT

The situation facing the city as it decides how to approach Community Choice Aggregation is different from the circumstances surrounding most of the examples cited above. First other communities had as their first goal less expensive power for their citizens and businesses. San Francisco has multiple aims: - for affordable power, but also reliable power, cleaner generated power, social justice in the physical location of power resources, and a robust set of energy efficiency services and local distributed generation resources (including solar). This indicates a far more activist role in shaping the power portfolio than exists in other community aggregations like Cape Light or NOPEC.

Second, because of its existing Hetch Hetchy power system, San Francisco has performed some functions connected to CCA operation. This includes load forecasting, and power purchasing. However, these functions have been performed for a relatively predictable and discrete 150 MW municipal load with a relatively small number of accounts. In contrast, CCA electricity sales volume volatility, a more diverse customer mix that could shift over time, and a need to integrate resource planning with ratesetting to match the customer priorities of the city, will all create a much more complicated load forecasting and power purchasing function for the CCA.

Third the SFPUC also has experience with customer care related to serving customers with water and sewer services. However, a CCA will not be billing customers for electricity supply: that function will remain with PG&E. Nonetheless CCA customer care will need to address billing, service and product related questions.

3.1 <u>How Should the CCA Be Organized?</u>

As the city contemplates its organizational options for CCA operation, including the degree of internalized functions, there are a number of organization structures from which to choose. For San Francisco, the organizational platform choices appear to be: -

Expanded Hetch Hetchy organization. If the goal for the SF CCA is primarily to offer greener power resources, the organizational platform could be an expansion on the existing SF Hetch Hetchy power organization's operation and procurement functions now serving municipal load.

Memorandum of Understanding between SF PUC and SF Environment. If SF also wants to plan and execute energy efficiency and distributed generation (DG) services, the organizational platform could be a joint action agreement by the SF PUC and SF Environment.

New, stand-alone CCSF energy enterprise. If SF anticipates it will want the ability to own power resources serving the community, or to expand to serve customers outside San Francisco as a joint powers authority serving other city or county CCAs, then a new stand-alone energy enterprise might be an appropriate structure. The organization might be more akin to the SF port.

Combining the issues of Section 2 (degree of contracting) with those or organizational platforms the fundamental decision the city will face involves two dimensions: a) how much change there is to the existing organizational framework, and b) the degree of contracted CCA functions.

The four potential outcomes, along with their respective functions and logical responsible parties are illustrated below.

A. Should the CCA Work from a base of the existing City departments structure?

Option A1 Use the existing department structure, with a high degree of contracting for CCA functions.

Option A2 Greater consolidation of functions now in the existing SFPUC divisions, with greater internalization of functions than for A1.

In either case, the distribution of functions might include:

- Expand Hetch Hetchy Water & Power to handle power procurement design for SF-CCA;
- Expand SFPUC customer service function;
- Expand EE & DG services managed by SF Environment;
- Advisory rate review assigned to Rate Fairness Board, with Board of Supervisors as the final authority;
- Assign more comprehensive responsibility to the SFPUC Commission or create a new CCA oversight body to integrate these functions;
- Overall policy guidance from SF Board of Supervisors.

B. Should CCSF Create a single new SF Energy organization to serve CCA loads?

Option B1 City contracts out most functions to supplier, including:
  - load forecasting, power portfolio management, settlements
  - business services functions
  - SFE could handle customer EE & DG development and information/outreach activities, but contract out actual delivery of program services

Option B2 City performs many functions with the existing and an expanded City work force
  - build internal capability to deliver all functions and services

3.2 What are the CCSF Organizational Capabilities?

As noted above, the city has organizational capabilities on which it could build to perform CCA functions. Table 3 lists CCA functions and whether the city provides any of these now. In addition, the city will need an overall governing authority (e.g. Board of Supervisors, SF PUC commission, and/or a CCA Oversight Board) to provide policy guidance and oversee the costs and rates for the CCA services.

Table 3. CCA Functions and City Capabilities

CCA Function	City Existing Capability?
1. Sales & Marketing	No
2. Customer Opt Out Notification & Processing	No
3. Customer Care	Yes - SFPUC has a customer call center for issues related to bi-monthly water & sewer billing. Potentially could incorporate responses to CCA billing inquiries.
4. Load Profiling and forecasting	Yes – HH does this for municipal power load but would need additional resources for community-wide load forecasting.
5. Resource Planning, Portfolio Structuring, Product/Service Offerings & Pricing (including EE programs)	HH Power Policy staff now work on resource portfolio choices both for HH and larger community (see ERIS) Some DG services analyzed by Power Policy staff. SF Environment analyzes need for community EE services.
6. Electricity Portfolio Supply and Management	Yes - HH Power Operations now does procurement, risk management, & settlements for municipal load. CCA would greatly expand and complicate this function. Would need to expand & upgrade staff skills.
7. Power delivery Scheduling	Not currently
8. Communication/ coordination with CAISO	No
9. Supplier Contract Administration	No
10. Delivery of EE & DG services	Yes - HH Power Policy staff does EE and DG for municipal buildings; SF Environment delivers community based EE programs under contract w/ PG&E, and Generation Solar community program under HH funding.
11. Rate Setting	Not for electricity but SFPUC conducts for water and sewer rates.
12. Risk Management, Performance Monitoring, Cost/ Revenue/ Profitability Analysis	HH does this supplying municipal electric load.
13. Bill Verification and Accounts Receivable	HH Power Operations now performs for municipal accounts but would more resources for the large number of CCA accounts.
14. Regulatory Affairs	Yes - HH Power Ops have FERC & CA ISO experience; Power Policy staff has CPUC experience.
15. Legal support (contracts, power, regulatory)	Yes - City Attorney's Office provides legal support for appearances before the CPUC, CEC and FERC.

4. HOW SHOULD THE CCA ENSURE CONSUMER PROTECTION AND RESPOND TO CONSUMER COMPLAINTS?

Any CCA implementation plan filing with the CPUC has to address specific consumer protection and consumer complaint processes undertaken by the CCA. Since PG&E, under AB 117, is required to be the CCA billing agent as well as to continue in its role regarding customer connections/disconnections the range of new consumer protections available to a CCA appear limited. However one area that the CCA can directly influence is opt-out notification and processing. This is a subject for Phase 2 of the CPUC CCA proceeding and here CCSF will pay particular attention to rights of consumers to have a reasonable opt-out process that is fair to all parties. Another subject for Phase 2 of the CCA proceeding is apportionment of customer payments between PG&E and the CCA. Currently direct access rules do not allow for customer disconnection for non-payment of the generation supply portion of the bill. This provision could harm CCA revenues and create higher rates for CCA customers who pay their electric bills on time. Again CCSF will be seeking changes in this current standard to ensure timeliness in CCA revenue collection.

The existing Consumer Complaint process at the SFPUC for water and sewer complaints appears to work reasonably well with the great majority of complaints satisfactorily handled by SFPUC staff. However the CPUC may require the demonstration of a more formal process. At this stage it appears that individual consumer complaints (as opposed e.g. to more generic concerns about rate impacts and rate changes) will be restricted to three items: - a) errors relating to opt-out processing where customers are inadvertently assigned either to PG&E or the CCA, b) errors relating to assignment of customers to incorrect rate schedules by the CCA, c) disputes regarding any individual contracts established by the CCA e.g. with large customers. It is anticipated that any individual consumer complaints will be addressed and reconciled by the CCA call-centre, however the CCA may have to establish a more formal complaint process – handled e.g. by a CCA Rate Fairness Board or the existing water and sewer Rate Fairness Board[1] – to resolve some disputes.

5. HOW SHOULD CCA ORGANIZE TO ACHIEVE ENERGY EFFICIENCY AND DEMAND REDUCTIONS?

An integral part of determining the City's CCA organization structure is to choose the most appropriate delivery mechanism for demand reduction services. Demand reduction can be achieved on the demand side by energy efficiency, load management and demand response programs, and on the supply side by facilitating deployment of customer side generation e.g. via solar installations. Delivery and administration of these services should be provided using the organizational form that will best meet the needs of the CCA, its customers and the city.

The supplier contracted to supply electricity to CCA customers will work in conjunction with the CCA will develop a resource plan that integrates wholesale energy portfolio

[1] A Charter Amendment is required to increase the scope of duties of the existing Rate Fairness Board.

management and demand reduction services to provide reliable and reasonably priced energy. This Integrated Resource Plan (IRP) will help determine the amount of demand reduction needed during specific time periods to provide the CCA an optimal power portfolio. Reducing power purchases during the most expensive time-periods will benefit all customers in addition to lowering the bills of customers who contribute to load reduction.

The options available for delivery of demand reduction for CCA customers match the four options outlined in Section 2.

5.1 Should the CCA Contract for All Demand Reduction Functions?

In this case, the supplier or its subcontractor/s will design, manage and deliver all demand reduction services. This will likely provide the least financial risk to the supplier portfolio management. If the supplier has a long-term contract (e.g. ten years), its interests will be long term and likely to conform to the city's interests. If supplier contracts are shorter (e.g. three years) then it is more likely that programs will not be designed to deliver persistent savings and customers could be frustrated by a changing array of contact people, phone numbers, email addresses and websites.

5.2 Should the CCA Contract for Most Demand Reduction Functions?

In this case the city performs some program functions (e.g. marketing) while contracting out a significant part of the daily operations to the supplier (e.g. energy auditing of buildings) or to other specialized energy efficiency/demand reduction firms. This option reduces the risk to the supplier because it keeps the supplier involved in the program and aware of its progress. Any failings in the programs will become apparent during program operation months in advance of an actual need to purchase power on the spot market. By hiring a contractor, the program can acquire the specialized marketing, financing and engineering services needed to create a flexible and dynamic program. This option allows for maximum integration of marketing and customer service functions with other city activities, e.g. co-marketing with the recycling program, reducing costs and improving program cost-effectiveness.

5.3 Should the CCA Contract for Some Implementation-Only Demand Reduction Functions?

The city assumes more of the responsibility for designing, monitoring and evaluating supplier programs. The city may retain some functions, e.g. customer service. The supplier and its subcontractors perform all other program delivery functions. This option provides even greater risk protection to the supplier while protecting the city interests. Utilizing other city capabilities will require a high degree of coordination between the supplier's contractor and city staff, perhaps raising costs and perhaps decreasing cost-effectiveness.

5.4 Should the City Perform All Demand Reduction Functions?

In this case, the city would hire all program implementation staff to design, manage, and deliver all demand reduction services. This would provide continuity to program operations and allow marketing channels to be developed and personalized consistently over time. The city can design programs to conform to the long-term interests of the CCA and the customers – this could well include a sales function whereby the program implementation staff is also responsible for customer retention and design and marketing of any special targeted rates. However the city purchasing and personnel requirements can make programs inflexible, unable to respond to market needs for different expertise and level of activity, diminishing the ability to deliver the demand reduction planned in the IRP. This would pose a significant risk for wholesale contracting and create larger hedging costs to reduce portfolio risk, in turn causing CCA rates to rise. Overtime this could erode the economic viability of the CCA.

5.5 What are the City Demand Reduction Capabilities?

A municipal demand reduction program can use a variety of program strategies to attain the demand reduction goals of the supplier. The primary strategies are; information, technical assistance, incentives, and, local legislation.

Information efforts can include many standard outreach tactics as well as some grassroots tactics using City resources, e.g. posters in public places such as libraries, health clinics, and fire stations. . Materials and delivery of information can be designed for the needs of the market sector including content and language. Activities may be coordinated and possibly integrated with other activities of the City. For example, when the Department of the Environment has a booth at a neighborhood event, energy program literature is included. This is clearly a great strength of the city and should be utilized by the demand reduction program.

Technical assistance may include web-based self-administered energy surveys, on-site surveys, training, access to financing, access to screened vendors, installation quality and controls. The key to success in providing technical assistance is a combination of expertise and customer communication skills. While the city can hire generalists, it is not well suited to hiring highly specialized experts. For example, the city can hire energy auditors with general skills, but cannot keep full time an expert in direct digital controls for forced draft boilers. Specialized skills must be outsourced.

Incentives may be performance based, technology based, or process based (e.g. fast-track permitting) and provided to building owners, building managers or vendors.

Local legislation may be used to overcome market barriers or speed widespread adoption of accepted technologies and practices. This is a task only city staff may perform.

5.6 What are the Demand Reduction Program Design Approach Options?

There are various approaches to program design with each with its own strengths and weaknesses. This discussion looks at several approaches and discusses them in terms of their suitability to the program delivery options.

Most utility programs are technology centered. Cost-effective technologies are identified and programs are developed to increase market saturation. Efforts may be directed at manufacturers, vendors, and building owners/managers to educate, assist, finance, and fund all or part of the adoption of the technology. Typically, incentives are offered in rebates per unit sold or installed.

This can be started quickly and can move large amounts of products if the market responds. This works well for large and some medium sized businesses and sometimes in the residential market, though residential rebate programs have a high degree of free-ridership. It is difficult to control quality and certainty of savings with rebate programs. Working with manufacturers is not likely to be successful because SF is too small a market to have an impact on manufacturers.

Texas is using a performance approach, a standard offer, paying an incentive for kilowatt and/or kWh reductions. Energy service companies propose to secure kW and/or kWh in specific market sectors and the program monitors and pays for the performance.

The program will only pay for the reduction it needs and pushes almost all of the activity to the private sector. There are significant opportunities for abuse and quality control is a significant problem creating a risk of poor persistence of the savings. Further, contractors will tend to target the most cost-effective savings in a facility, leaving behind less effective savings that will be impossible to recover at a later date because the transaction cost is too high.

Efficiency Vermont has converted its demand reduction services to a customer-centered system, utilizing teams that focus on different market sectors. The teams develop relationships and knowledge of customer groups, their specialized needs, and determine which technologies and practices will meet their needs.

Developing these relationships takes longer and takes a greater up-front investment making the investment appear to be less cost-effective. It is likely to yield more comprehensive savings, particularly among commercial customers. Additionally, solutions that better fit the individual customer are likely to persist longer than the one-size-fits-all solutions and better contribute to transforming the local market. It is easier to go back through strengthened marketing channels to reach previous customers with new offerings.

6. A CCSF ORGANIZATIONAL APPROACH TO DECISION-MAKING

The decision to move forward with CCA for the city also requires a decision about a CCSF organizational approach. In determining what organizational model to adopt for CCA implementation a number of considerations have to be weighed.

6.1 Decision Considerations

- What place might CCA have in the long-term vision for the SFPUC, Hetchy Hetchy, and SFE missions? For example if Hetch Hetchy is tasked with the overall contracting and operation of the four combustion turbines that comprise the city's Peaker Project this is likely to require an expansion of Hetch Hetchy staff and skills. Could this staff expansion be enhanced to incorporate overall responsibility for CCA implementation?

- To what extent does the city wish to "brand" CCA as a CCSF government activity? Public identification of city government as the controlling force behind CCA requires a significant degree of city control over the day-to-day activities of the CCA. This in turns means staffing these CCA functions with city employees.

- What is the city's risk tolerance? There is a direct correlation between risk and the level of responsibility for the city assuming CCA functions. Simply put suppliers have substantial experience in conducting the business of being a supplier. For many functions the city would be starting from a limited base of experience and skill sets.

- Is the city willing to trade off potentially higher costs for greater control and public branding? Suppliers of all types bring significant economies of scope and scale to performing many of the CCA functions. If the city undertakes a number of these functions, it may experience higher costs than a supplier s.

- What is the cities timeframe for implementation? Does the city want to implement CCA as soon as possible? Or is the city willing to slow-down CCA implementation so as to conduct the organizational and staffing implementation steps necessary to perform key CCA functions? A decision to staff key CCA functions with city employees will in turn raise organizational and staffing classification issues. This may result in delays in starting a CCA.

- Will choosing a Phase-In approach to CCA help the city in undertaking key CCA functions? As discussed in the Executive Summary a Phase-In approach to CCA has a number of benefits as well as significant drawbacks. Assuming the city undertakes a number of the key CCA functions Phase-In offers the advantage of allowing for a gradual build-up of staffing for these functions. This would provide for greater accuracy regarding both staffing counts and types of staff actually required based on early experience.

6.2 Decision Timing

Chapter 1 - the Executive Summary - provides a time-line for potential CCA implementation (or alternatively a further study period prior to making a decision on CCA). That time line assumes that the supplier undertakes the majority of CCA functions. If, however, the city chooses to assume a number of key CCA functions itself, there may be some delay in CCA start-up. Table 4 below presents a time-line for CCA implementation assuming a substantial number of CCA functions are undertaken directly by the city. While the timeline remains the same, as that set forth in the Executive Summary a key assumption point is that the decision-making regarding which CCA functions to undertake would be completed by December 2005. Any delay in this decision-making will result in delay in the hiring/training periods assumed in this table and therefore a delay in the start-date for CCA.

Table 4. Potential CCA Implementation Timeline and Milestones Incorporating Staffing of Some CCA Functions.[2]

CCA Proceed Decision by BOS	**July 2005?**
Implementation Plan filed with CPUC	**October 2005**
RFP Circulated to Suppliers	**October 2005**
Organizational Implementation and Staffing Decisions Approved	**December 2005**
Staffing Implementation Begins	**January 2006**
CPUC Approves Implementation Plan	**January/February 2006**
City Communications Outreach to Electric Customers	**May-December 2006**
Staffing Implementation Completed – Staffing Training Commences	**September 2006**
Contract Approved and Signed with Supplier and Approved by BOS	**September 2006**
Service and other Agreements Signed With PG&E	**September 2006**
Mass Communications Project Commences re Opt-Out Process	**October 2006**
Opt-Out Processing of CCA Customers Commences	**January 2007**
CCA Begins Power Deliveries	**March 2007.**

[2] This time-line assumes the CPUC would not need the actual identity of the CCA's wholesale electricity provider as part of the Implementation Plan Filing. This matter is a subject for Phase 2 of the CPUC CCA proceeding.

6.3 What are the Start Up Costs?

There are two key issues related to start-up costs. First start-up costs for the six months or so prior to CCA implementation could be considerable. The Departments estimate that in the 6 months of CCA activity prior to day 1 of CCA implementation the CCA cost could be at least $5 million.[3] . Second what funding source is available for the start-up costs that occur prior to receiving revenues from customers? Although it is possible that reimbursement for some of these costs may be possible – depending upon the RFP terms and conditions – the city will need to identify a funding source for these expenditures. Again a Phase-In approach to CCA implementation may allow for an incrementally smaller expenditure for some of these tasks, while allowing revenues received to fund subsequent Phase-In efforts.

[3] This comprises some ballpark estimates of about $3 million for communications outreach including opt-out notification, $0.5 million for a customer call centre, and $1 million for consulting assistance on the Draft Implementation Plan and RFP work, and $0.5 million for contingencies.

Community Choice Aggregation Draft Implementation Plan

Chapter 8: Communications Plan

Prepared for
The City and County of San Francisco

By
RIDLEY & ASSOCIATES, INC.

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1. Draft Communications Plan Description

1.1. Overview

Community Choice Aggregation is a method to gather the bulk purchasing power of consumers to negotiate an electric supply contract beneficial to residential, municipal, and business consumers. It can produce both direct and indirect benefits including efforts for development and use of renewable energy, energy efficiency, enhanced reliability, pollution reduction, and infrastructure development.

On September 24, 2002, California enacted Chapter 838 and authorized municipalities to undertake Community Choice Aggregation programs. The San Francisco Board of Supervisors (BOS) approved an Ordinance on May 18, 2004 to establish a Community Choice Aggregation Program.

The *Draft Communications Plan* has been prepared as part of the *Draft Implementation Plan* for San Francisco's Community Choice Aggregation Program (CCSF) The *Draft Communications Plan* is intended to describe in a preliminary way the scope and steps for establishing internal and external communications essential to development of the CCSF. It outlines a potential chronological development of a structure for public education; some ideas regarding management of the customer notification process required by statute; a potential approach to setting up customer enrollment; and integration with marketing and sales and customer care It also outlines the relative roles of an Electric Service Provider (ESP) and Pacific Gas and Electric (PG&E) and the necessary communications coordination and information transfers between these parties.

The *Draft Communications Plan* describes a possible organizational structure, potential staffing, and a first cut at estimated budgets and funding – which is best described as bare-bones, and key themes to be used in a CCSF communications strategy. It includes a description of specific tasks and needs of a CCSF communications program and suggestions for best practices.

Because state regulatory rules and policies are still being promulgated, the substance, timing, and budget related to the elements and suggestions in this *Draft Communications Plan* will probably need to be altered. The Draft Plan may also be altered by policy determinations concerning market testing, program costs, or responsibilities to be shared with the ESP or PG&E. The information in the Draft Plan is intended to be tested and refined.

The Draft Plan is divided into four sections. Section 1 provides a general description of the stages of communications development and associated tasks and activities for: Pre-Program Communications; Program Start-Up; Customer Enrollment; Post-Enrollment; and Established Program Operations. It also provides a summary of suggested themes and messages. Section 2 focuses on Short Term Implementation. Section 3 focuses on Long Term Implementation. Section 4 is an Appendix section that contains the *Organizational*

Chart, Estimated Budget, General Timeline, four sample *Notification Letters* and *Frequently Asked Questions* Sheet.

1.2. Pre-Program Communications

The general purpose of Pre-Program Communications is to establish a base for a more formal communications program. It offers a flexible approach for initiating CCSF development that can extend through a period of program development and power supply acquisition. It also allows early outreach and media contacts and direct contact with key groups. There are two phases for Pre-Program Communications

1.2.1. Phase I: Initial Pre-Program Communications Activities

The first phase is coincident with general planning for the CCSF program and includes general or informal meetings with customer groups, business and civic organizations, and community leaders to explain the planning for the CCSF and its goals. A first round of meetings with editorial boards and opinion-makers is also highly useful at this stage. Efforts could be made to gather letters of support, or to generate initial articles or editorials. Coincident with this activity, a plan for direct informational mailings to key customer groups could be developed and implemented. The support letters, articles, or editorials could be used as part of a mail package to specific groups. The purpose of this activity is to initiate effective outreach to key customers and to begin laying a firm base of information prior to BOS review, discussion, and determination on the CCSF *Draft Implementation Plan* (which will generate a second wave of articles/editorials/news coverage and public discussion).

Primary themes and messages could be tested as part of the Phase I meetings and initial mailings. Themes and messages could be further developed based on responses. The general strategy should rely upon a background theme, a foreground theme, and messages developed from that context. (See Section 1.11 for discussion on CCSF theme and message options.)

1.2.2. Phase II: Advanced Pre-Program Communications Activities

The second phase commences with BOS approval of the CCSF *Draft Implementation Plan* (including a communications component) and adoption of a budget for program communications. This would allow planning and launch of a formal communications effort. The second phase would need to include formulation of a detailed media plan and a timeline based on California Public Utility Commission (CPUC) approval of the CCSF *Draft Implementation Plan* and CPUC rules and policies concerning CCSF implementation. This Communications Plan could include an integrated mix of tasks related to news media and advertising that would complement a parallel Marketing and Sales Plan. While there are shared tasks in development of themes, messages, and information; application and tasks related to the Communications Plan and the Marketing and Sales Plan are very different and it is assumed marketing and sales will be carried on by a separate task group. This *Draft Communications Plan* focuses on media work related to public education and

development of processes related to required customer notifications, as well as development of program structure for effective communications with PG&E and the ESP. Responses to Communications Plan activities could serve to inform the Marketing and Sales Plan.

The Communications Plan would be utilized during Program Start-Up, Enrollment, and Post-Enrollment periods. An early portion of the Communications Plan would also be utilized during Phase II activities and include a press conference on BOS approval of the CCSF Plan and press releases for CPUC determinations and issuance of an RFQ or RFP for power supply.

For combined purposes of public education and communications development, first phase meeting activity could continue during the second phase with meetings targeted for specific groups or individuals. Initial meetings could also be planned with PG&E to prepare for coordination of activities noted below in section 1.3.2.

The primary themes and messages of Phase I would be continued during Phase II and additional theme and message testing could be conducted as part of the meetings to assist with the Communications Plan and Marketing and Sales Plan formulation. (See sections 1.10 and 1.11)

1.3. Start-Up

Following detailed preparation work and implementation of essential early elements noted above, Start-Up of the full communications program would commence with the execution of an Electric Supply Agreement (ESA) [or a Day 0 resulting from schedule determinations of the CPUC]. Start-Up consists of simultaneous activities for: implementation of the Communications Plan; coordination between PG&E, ESP and CCSF to develop integrated communications and customer care; and coordination between PG&E, the ESP and CCSF to prepare the enrollment process.

The Start-Up schedule would be driven by both statutory requirements and rules and policies established to implement those requirements. The law requires that the CPUC: "shall designate the earliest possible effective date for implementation of a community choice aggregation program . . ." [Ch 838, Section 366.2, Subsection 8] The law also requires that: "Once the community choice aggregator's contract is signed, [with a supplier] the community choice aggregator shall notify the applicable electrical corporation that the community choice service will commence within 30 days." [Subsection 15] It also requires that: "Once notified of a community choice aggregator program, the electrical corporation shall transfer all applicable accounts to the new supplier within a 30 day period from the date of the close of the normally scheduled monthly metering and billing process." [Subsection 16]. How these statutory requirements are addressed, particularly the date of the CCSF notification to PG&E, could significantly determine the pace of activities, much of which will need to take place for Start-Up prior to that notification.

1.3.1. Implementation of Communications Plan

Based on adopted rules and policies and a projected timeline for CCSF implementation, the detailed Communications Plan developed under section 1.2.2 activities could begin with a press conference and distribution of a media package including a news release on the signing of the ESA and the resulting estimated benefits. It could also include information on the ESP. [The ESP should fund all or a major portion of this media strategy.] The initial release could also announce that consumers will begin receiving letters concerning the CCSF that will offer them the opportunity to take advantage of electric service benefits, and inform then that they can choose not to participate (opt-out).

Additional information on the CCSF, the ESA, the ESP, and timelines should be made available on the CCSF website. With the kick-off of the Communications Plan, customer care representatives for PG&E, the CCSF, and the ESP would also need to be prepared to address consumer questions in a coordinated and consistent manner as noted below in section 1.3.2.

1.3.2. Coordination of Communications with Supplier and PG&E

Customer care, communications, and Information Technology (IT) staff would need to coordinate efforts for customer care and transfer on a timely basis. Initial meetings to address the need for and identification of potential members of a coordinating committee between PG&E and the CCSF should take place during section 1.2.2 activities. With the signing of an ESA, the ESP would also need to designate staff to be added to this committee.

Communications would require coordination of PG&E, CCSF and ESP customer care representatives to answer questions and assure consistency in key messages being provided to the media and to customers. It would be important to identify a central information source [likely the ESP customer care representatives] to respond to direct customer questions. A secondary source would also be needed to address questions on more detailed technical or program matters beyond the scope of the customer care representatives [a CCSF source]. A third source would be needed to respond to media questions [a CCSF source]. The coordination between PG&E, the CCSF, and the ESP for referral of questions should follow provisions included in contractual agreements.

As communications plan efforts are increased, customer care representative are likely to find an acceleration of public questions beginning with the signing of the ESA. A timeline and meeting schedule for coordination would need to be developed. The coordinating committee would need to meet weekly and continue with timely communications among specific members on a daily basis throughout the start-up and enrollment period. [See Section 2 "Short Term Plan Implementation" for elements that would need to be addressed.]

1.3.3. Preparation for the Enrollment Process

This is an important stage that also requires close cooperation among the CCSF, the

PG&E, and the ESP. Data files for the prospective customers need to be prepared by PG&E and transferred to the CCSF and ESP on a timely basis. PG&E should exclude from the data list any customers who are not eligible to participate in the CCSF. PG&E and the ESP would need to ensure IT functions are compatible for the enrollment process. IT enrollment needs to be tested for processing of large groups of customers on a daily basis and any problems resolved.

While the IT enrollment process is being established, the CCSF would need to arrange for a mail house to print, mail, and track and record the opt-out responses received. [If oral telephone opt-out responses are acceptable, then the records of the written and oral opt-outs need to be combined.]

The four notification letters should also be prepared and a timeline established for mail drop, tracking, and summary of responses. Suggested format and language for the two pre-enrollment notifications are described in section 1.4.2, and suggested format and language for the two post-enrollment notification letters are described in section 1.5.1.

1.4. Customer Enrollment

There are three phases for customer enrollment. Phase I is official start-up of the customer call center. Phase II includes the two pre-enrollment mailings and management of responses and returns. Phase III is the IT enrollment process.

1.4.1. Phase I: Customer Care Call Center Official Start Up

As noted above in section 1.3.2, early start-up of Customer Care should commence following the announcement of execution of the ESA and be prepared to answer general questions on the CCSF, the composition and pricing of power supply, the enrollment and opt-out process, and the ESP. This function would increase over time with customer responses to additional news articles or news features, advertising and mailings, and notification mailings. The full operation of a customer call-in center would begin just prior to the first notification mail drop, and be aimed specifically at responding to customer questions on the mailing. Communications staff should be part of this process to prepare scripts and prepare answers to frequently asked questions, and to track issues of consumer concern. The bulk of this work would follow through the fourth notification, although staffing may be moderated based on call response. Following the notification period, the customer call-in center would be staffed at established operational levels based on anticipated call volumes and need for communications assistance.

1.4.2. Phase II: Pre-Enrollment Notification Mailings

The statute requires four consecutive notifications, which imply a 120-day period based on 30 day billing schedules, although the language of the provision allows some latitude stating: "Notifications may occur concurrently with billing cycles." [subsection 13A]. The CCSF can also request that the CPUC approve an order that PG&E transmit the notification mailings in monthly billings, with PG&E recovering all reasonable incremental

costs. The law also offers other options: "Notification may include, but is not limited to, direct mailings to customers, or inserts in water, sewer, or other PG&E bills." [Subsection 13A] If phase-in of enrollment of customers is allowed for the implementation of the CCSF program, then notification mailings for each phased group will need to be developed and tracked. For discussion purposes, the notifications are examined as a single group below.

Due to the importance of the four notifications and consequent responsibilities, the CCSF should exercise maximum control over the content, schedule, and tracking of the mailings. A separate letter mailing to each customer conducted by a mail house for the CCSF for at least the two pre-enrollment mailings is advisable. [Unless significant savings and other beneficial terms are available through use of PG&E mailing operations.] It may also be possible to split the source of the mailings, with the first two notifications through a CCSF mail house, and the second two notifications through PG&E mailing operations.

The two pre-enrollment customer notifications could consist of a letter, a business mail return card (for opt-out), and a FAQ sheet. The law states: "Each notification shall also include a mechanism by which a ratepayer may opt out of community choice aggregation service. The opt out may take the form of a self-addressed return postcard indicting the customer's election to remain with, or return to, electrical energy service provided by the electrical corporation, or another straightforward means by which the customer may elect to derive electrical energy service through the electrical corporation providing service in the area." [Subsection 13C] The envelope should be marked "Important Consumer Notification Enclosed" on the address face with a CCSF mail house return address [or address of the processing center]. The notification letters will need to prominently note a telephone number for translation services for specific minority language groups [determined by the CCSF and CPUC].

The statute requires that each notification "fully inform participating customers" that: 1) they are to be automatically enrolled and have the right to opt out without penalty; 2) the terms and conditions of the services offered. [Subsection 13A]

Given the required content, the period between mailings, and the fact that a high percentage of PG&E notifications are not read by consumers, it will be necessary for a certain amount of repetition between the pre-enrollment letters. Differences between the letters can also be marked by a progression of the emphasis of the message and graphics that might be used on the letters.

(See discussion of notification letter messages and submessages contained in section 1.11)

1.4.3. Phase III: IT Process Opt-Out Tracking

The opt-out period would continue for 30 days [or an interval determined by the CPUC] following the mail date of the second notification. On a rolling basis, or on completion of the opt-out period, the mail house should gather the recorded and returned opt-out cards for removal of these customers from the prepared enrollment list. [If opt-outs

have also been gathered via telephone requests, CCSF customer care representatives should transmit written records of telephoned oral opt out requests that should also be extracted from the enrollment list.] The notifications returned as undeliverable should also be removed from the enrollment list.

The enrollment list needs to be prepared according to the process established during section 1.3.3 activities [either by the CCSF and transferred to the ESP, or by the ESP] and submitted under established enrollment protocols to PG&E.

1.4.4. Phase III: IT Enrollment Process

The enrollment process is a function of Information Technology (IT) transfers between the ESP and PG&E according to established protocols. The process for setting up and managing enrollment should be accomplished with the Start-Up activities in section 1.3.3. The system should also be tested during Start-Up (section 1.3.3) or during the Customer Call Center Operation (section 1.4.1) activities. With the process set up and tested, enrollment can proceed.

Assuming a maximum customer base of approximately 351,000 customers, and enrollment proceeding over a 21-day cycle of billing reads, the enrollment process would need to transfer on average approximately 16,800 customers per day to the ESP. The actual daily number may be higher or lower, depending upon PG&E meter-read and billing schedules. The number of opt-outs and undeliverables removed from the customer base will also affect the average daily number of enrollments.

1.5. <u>1.5 Post-Enrollment</u>

Post-Enrollment is focused on clean up of the enrollment notifications and establishment of an on-going system. It consists of four parts: 1) two post-enrollment mailings; 2) mailing to returns and catch-up on new customers; 3) setting up a process for customer care monitoring; and 4) setting up a notification mailing process to new customers (movers). It also requires on-going media/advertising activities consistent with the Communications Plan.

1.5.1. Post-Enrollment Notification Letters

There are two required post-customer enrollment notifications (the third and fourth notifications). The law requires: "Following enrollment, the aggregated entity shall fully inform participating customers for not less than two consecutive billing cycles." [assumed 60 day period] [Subsection 13A] These two notifications would also be in a letter format. However, the rescission process could be conducted via telephone by the customer to the customer call center, eliminating the need for tracking, recording and handling a business mail return card. [If this is acceptable under the CPCU rules.] Direct mail through a mail house, however, may offer the best form for sending the notification letter to the customer. [Unless PG&E mail operations are determined to be beneficial for the two post-enrollment mailings.]

Both Post-Enrollment notification letters would also need to prominently show a telephone contact number for translation services for specified minority language groups. If an opt-out card were not included, then the post-enrollment package would consist of a printed envelope stating "Important Consumer Notification Enclosed," the notification letter, and the FAQ sheet.

1.5.2. Mailing Returns and Catch-Up

Each notification mailing will result in a certain number of mail pieces returned as undeliverable due to problems with the address, or the fact that the customer has moved and may or may not be within the service territory. A review should be made (by comparison to an updated customer list from PG&E) to determine which addresses to correct and re-mail and which ones to eliminate.

The updated customer list from PG&E would also indicate new customers who have entered the service territory between the time the first list was pulled and processed for mailing, and the final opt-out notice. A "catch-up" mailing of the four required notifications should be started for these new customers. While this "catch-up" could be started at the time of the second mailing, holding the "catch-up" for a batch mailing will allow a more coordinated approach. If a single notification mailing, rather than four notifications, is allowed for the "catch-up" group, the letter and process could follow the example of the "refresher" mailing noted in section 1.5.3 below. The use of phase-in enrollment for the implementation of the CCSF program [if allowable] would complicate the "catch-up" process by creating more "catch-up" groups. These groups could be held and batched for a single mailing, although time delay would be a factor for consideration.

[See Section 2 "Short-Term Plan Implementation" for more discussion on these issues.]

1.5.3. Setting Up Refresher Mailings for New Customers

Similar to the "catch-up" mailing, a data listing of new customers should be transferred from PG&E to the CCSF [or directly to the ESP] each month. This will allow timely mailing of the four notifications [or a single notification if allowable for "refresher" mailings] to be sent to the new customers, and for them to enter the enrollment process. The notification letters should be revised to reflect the fact the customer is joining an existing customer group.

1.5.4. Monitoring Customer Care

It is important to set up a process to periodically review customer care and identify and help assure the resolution of generic problems in a timely manner. The simplest process is to establish a reporting form for customer call center representatives and to review the results of that form on a weekly basis (or more frequently if particular problems are being tracked). This process requires ESP communications, and may also involve PG&E customer care staff.

[See Section 2 "Short-Term Plan Implementation" for more detailed information on the period of Pre-Communications through Post-Enrollment.]

1.6. Established Program Operations

Beyond the Post-Enrollment period, communications activities for the established program would need to include management of on-going media and advertising; monitoring and timely internal communications between the CCSF, ESP, and PG&E customer care staff; management of on-going enrollment notifications and communications for new customers entering the program. If other energy services are added to electric supply, preparation for these services would need to be undertaken. The preparation of newsletters or periodic notices and customer information could also be undertaken outside of the core activities. The established program will also need to prepare and implement a process for ESA renewal, or perhaps customer transferal, at the close of the ESA duration.

[See Section 3 "Long Range Plan Implementation" for more detailed discussion.]

1.7. Organizational Structure

The organizational structure for communications should follow the primary responsibilities for the services of the CCSF. As a practical matter, the CCSF, the ESP, and PG&E all have specific roles to play. Generally, the integrated functions of all three parties would need to be guided by a coordinating committee, and/or specifically identified individuals who maintain frequent contact established during the Start-Up period activities in section 1.3.2. Roles and responsibilities that make up the organizational structure of CCSF operations would be reflected in agreements with the ESP and PG&E. The ESP would have the lead technical role in customer enrollment and customer service delivery (including operation of the customer care center). PG&E would play a support role in customer enrollment and in referral of customers for specified customer care services.
It is assumed that the CCSF would outsource most major tasks in the short term; utilizing technical consultants to the extent necessary; and maintaining a policy-making, management, and oversight role.

For the Communications Program specifically, the CCSF would have the lead role in media and customer communications. At an administrative level, communications staff should participate in the development and implementation of program strategy decisions, and shape the messages resulting from those decisions. Communications staff would be important participants in a coordinating committee with the ESP and PG&E. The Communications Program would oversee customer education and the customer notification process, and assist with the enrollment process. Communications staff would also work to assure consistency of ESP and PG&E customer education and advertising, and with the Marketing and Sales staff monitor customer care functions. Communications staff would answer directly to CCSF executive management and manage consultant services related to communications activities and tasks. Below is a discussion of development activities of the

CCSF program and assumed responsibilities for communications staff to provide support, or carry out tasks.

[See Appendix section 4.1 Communications Plan Organizational Structure chart.]

1.7.1. Pre-Program Communications

Assumed responsibility: Section 1.2 activities are carried out by CCSF communications staff and consultants for both Phase I and Phase II. Meetings are led by communications staff with consultant support. CCSF staff and consultants develop a Communications Plan, which is coordinated with a Marketing and Sales Plan.

1.7.2. Program Start-Up

Assumed responsibility: Section 1.3 activities are led by CCSF communications staff with support from consultants for simultaneous efforts. The communications program is fully implemented by the CCSF with ESP participation. The CCSF leads the coordinating committee consisting of CCSF, the ESP, and PG&E to develop enrollment schedules. The ESP, with oversight from CCSF, works with PG&E to develop an integrated customer care program. The ESP with oversight from the CCSF works with PG&E to prepare the IT enrollment process. The CCSF develops the mail notification process.

1.7.3. Enrollment

Assumed responsibility: The CCSF oversees the pre-enrollment notification process and media. The ESP operates the customer care center with oversight from the CCSF. At a minimum the CCSF will need to monitor customer questions and complaints and address special problems in customer care that arise in the enrollment process. The ESP and PG&E conduct the IT enrollment process. Media and advertising related to notifications (as differentiated from Marketing and Sales advertising) proceeds consistent with the Communications Plan.

1.7.4. Post-Enrollment

Assumed responsibility: The CCSF oversees the post-enrollment notification process and "catch-up" mailing and media. The ESP operates the customer care operation with oversight from the CCSF. The ESP and PG&E conduct the IT enrollment process and the customer rescissions. Media and advertising related to notifications proceed consistent with the Communications Plan.

1.7.5. Established Operations

Assumed responsibility: The CCSF oversees notifications of new customers, customer care and media work. The ESP and PG&E conduct the IT enrollment process and customer rescissions. The CCSF prepares for ESA renewal or customer transfer.

1.8. Staffing

Staffing for CCSF communications would follow the responsibilities outlined in section 1.7. The level of staffing would be determined by three basic elements: 1) core activities and operations; 2) agreement between the CCSF and ESP on division of responsibilities; 3) technical expertise of the CCSF staff, and/or need for consultant support. Each of these elements would be guided by funding considerations.

For the purpose of this discussion, minimal communications staffing has been assumed: one full time supervisory position, and one full time senior communications manager, and one part-time administrative assistant.

1.8.1. Pre-Program Communications

As noted in section 1.7.1 Pre-Program activities are the sole responsibility of the CCSF. The extent of the meeting and planning activities and budget would require the two full time staff positions during this stage, unless senior marketing and sales personnel are also available for pre-program work. If so, Phase I might be managed initially by one communications staff person with consultant and marketing and sales support, depending on the extent of activities. The core activities for Phase II Pre-Program activities, however, require a minimum of two communications staff positions and administrative and consultant support.

1.8.2. Program Start-Up

As noted in section 1.7.2, these activities are led by the CCSF, but involve the CCSF supplier and PG&E. CCSF core activities for development of a Communications Plan with consultants, participation on a coordinating committee, and enrollment preparation will require a minimum of two communications staff positions and administrative and consultant support. Additional support from Marketing and Sales senior staff might also be necessary.

1.8.3. Enrollment

As noted in section 1.7.3, the CCSF conducts the notification process and provides oversight for the customer care process and oversees media/advertising. CCSF core activities will require a minimum of two communications staff positions and administrative and consultant support. Additional support from Marketing and Sales senior staff might also be necessary.

1.8.4. Post-Enrollment

As noted in section 1.7.4, the CCSF oversees the post-enrollment notification process, catch-up mailings, oversight of media/advertising, and monitoring customer care. CCSF core activities will require a minimum of two communications staff positions and

administrative and consultant support. Additional support from Marketing and Sales senior staff might also be necessary.

1.8.5 Established Operations

As noted in section 1.7.5, the CCSF oversees on-going operations, notification of new customers, oversight of advertising/media, and monitoring of customer care. This will require a minimum of two communications staff positions and administrative and consultant support. Integration with Marketing and Sales activities would be beneficial. Later activities related to preparation for ESA renewal or customer transferal which may involve activities similar to Pre-Program Phase I and II would also require integrated support.

1.9. Estimated Budget and Funding

1.9.1. Estimated Budget

The estimated budget is based on core communications activities. The extent of core activities can be affected by the division of responsibilities between the CCSF and the ESP and responsibilities of other CCSF staff and consultants. As noted in section 1.8, this budget assumes minimal staffing for two full time positions for communications activities: one communications supervisor; one senior communications manager; and one part-time administrative assistant.

The Estimated Budget also assumes acquisition of low-cost printing and mailing services for notification mailings. The Estimated Budget also assumes the time periods for communications activities noted in the Communications Plan General Timeline. Most of the staffing costs have been frontloaded for the estimated 150-day development period for activities outlined in sections 1.2.1. through section 1.5.4. Direct costs for two enrollment and two post-enrollment mailings, as well as media, advertising, and customer care costs are broken out for each mailing. These cost assumptions, as well as those concerning staffing, consultants, and media/advertising will need to be revised based on additional information on staff costs and bids on final program specifications.

In terms of a general budget breakdown, for the Short Term Activities [Pre-Communications, Start-Up, Enrollment, and Post-Enrollment] costs associated with the four required Notification Mailings will likely comprise 54 percent or more of the Communications Budget. [For initial estimate purposes, this assumes a mailing to 350,000 customers containing a 2-sided letter, 2-sided FAQ, BRM card, and printed envelope at $0.35 for printing, insertion and mailing x 4 mailings= $490,000, plus $15,000 for a catch-up mailing=$505,000]. Costs associated with Media/Advertising could vary significantly, but for initial estimate purposes are assumed to comprise nearly 21 percent of the budget including Communications Plan development and media and advertising costs. [$200,000.] And costs associated with communications development and customer care development would comprise approximately 25 percent of the budget. [This would include both staff and consultant costs at a total of $237,500.] Based on these initial assumptions the

estimated total Short Term budget would be $942,500. A contingency of 15 percent increases this amount to $1,083,875.

For Long Term Activities in Established Operations, the total communications budget will be reduced from the costs associated with first implementing the CCSF program to a total of approximately $24,800/monthly or $297,600/annually. An additional 15 percent contingency increases this annual amount to $342,240. However, even at that lower scale, costs associated with the four required notification mailings for new customers are likely to remain at 40 percent or more of the Communications Budget. [Based on an average of approximately 7,000 new customers per month with 4 mailings at $0.35 each=$9,800/month.] Media/Advertising would remain at 20 percent of the budget. [Based on estimated costs of $5,000/month]. And management and development of communications and monitoring of customer care at approximately 40 percent of the budget. [$10,000/month]

[See Appendix section 4.1 Draft Budget Estimate]

1.9.2. Funding

The general goal of the CCSF program should be self-support through a combination of contributions from the ESP for advertising and customer education and enrollment and program revenues. This can be achieved once enrollment has occurred and revenue is flowing from customers. For the Communications Program, a substantial amount of the funds required for advertising, mailing and other activities related to customer education should be provided by the ESP, through agreements included in the ESA. For the Pre-Program stage and part of the Start-Up activities, however, funds appropriated for the CCSF will need to be budgeted and utilized. If the Pre-Program stage is extended due to market conditions delaying execution of an ESA, additional appropriations of Pre-Program funds may be required. If the ESP does not cover certain media or developmental activities during Start-Up, Enrollment and Post-Enrollment, additional funds will need to be appropriated for these categories as well.

1.9.2.1. Pre-Program Communications

Prior to signing of an ESA, the CCSF will need to fund activities for this portion of the budget. Some of these are expenses the CCSF may be able to recoup later, but essentially must be budgeted with public funds. As previously noted, there should be flexibility for the amount of spending at this stage, with activities designed to meet the available budget.

1.9.2.2. Start-Up and Enrollment

These activities take place after the signing of the ESA. The ESP should fund all or a significant portion of costs associated with the development of the program and education and acquisition of customers (i.e. costs of the notification process, advertising and media, CCSF participation in development of customer care, and other activities related to

enrollment). As noted above, funding for these activities needs to be included in provisions of the ESA.

1.9.2.3. Post-Enrollment and Established Operations

These activities commence after power supply and revenues are flowing and can be funded as part of very small operational charge per kilowatt hour (i.e. 3/100 of one cent $0.0003/kWh).

In addition, as noted under section 1.9.2.2, through provisions of the ESA, the ESP could fund the cost of notification mailings, advertising, and other customer and enrollment costs from which the supplier derives benefit.

Funds for communications for ESA renewal, or customer transfer, should be included in reserves gathered as part of the on-going operational charge.

1.10. Media Choices

The choice of media should include a standard mix of print, electronic, and direct mail, or e-mail, to target groups. Additional consideration should be made to place and distribute graphic/public message posters in segments of the mass transit system and public buildings. A common method of utilizing overlapping and repeated themes and messages scheduled to specific stages of the CCSF development should be utilized to gain maximum message penetration. Determination of specific media choices will depend to a large extent on the formulation of a Communications Plan noted in section 1.2.2 and the approved media budget. Press events and Public Service Announcements (PSAs) in print media, radio, and television should be used as frequently as possible to reduce costs.

The general purpose of the media portion of the communications program should be to promote the themes and messages to: 1) create general public familiarity with the CCSF and its purpose and base in "benefits and service"; 2) provide context and substance for events concerning the CCSF; 3) provide background and alerts for customer direct mail notifications; 4) market the program and provide education on energy issues and options and choices each consumer can make to save or use energy.

The draft budget assumes costs for: (Pre-Program) development of a Communications Plan; direct mail to key customer groups; (Start-Up/Enrollment/Post-Enrollment) general education of consumers concerning the opt-out and enrollment process through a Communications Plan mix of electronic and print advertising; (Established Operations) a follow-on education concerning the CCSF and its services.

1.11. Summary of Key Themes

Primary themes and messages should be tested as part of the Pre-Program Communications in Phase I meetings and initial mailings and more detailed testing should take place as part of development of the Communications Plan in Phase II. Themes and messages should be

further developed and clarified based on responses. The general strategy should rely upon a background theme, a foreground theme, and messages developed from that context.

The supporting or background theme could stress that "electricity is an essential service." This would resound with consumer experience, and provide a simple yet powerful basis for why the CCSF has been established. Coupled with this, the concept that "consumer benefits are possible through bulk power purchase" could be utilized.

The central foreground theme for the CCSF throughout all stages of development could be that of securing and delivering benefits to SF residents and businesses—providing "benefits and service"—in shorthand notation. The specific messages that flow from this foreground theme would depend on the character of the electricity product offered to consumers. The messages could reflect both direct and indirect benefits—and the multiple nature of benefits from the CCSF. If a renewable energy mix is the product offered, the lead note in the message could emphasize the individual and cumulative benefits of green power supply. In addition benefits related to increased collective consumer ability to ensure cost predictability, reliability and quality of service could back up this lead note). Ease of program entry and service delivery could be the third note. Opportunity to choose to opt-out could be the fourth note. Throughout the communications program the language of messages it would be advisable to focus on "services" and not "programs" for consumers. Any branding for "Community Choice" services should be associated with direct and indirect benefits that are both individual and cumulative.

The background and foreground themes and specific messages should be tested as part of the Communications Plan development and utilized at each stage to form a consistent overlapping stream.

In addition to conceptual themes and messages, a single attractive graphic image could be created to symbolize the program. Other attractive graphics could be created and utilized in posters—for which there could be public competitions. These graphic images could be used to support the conceptual text messages.

1.11.1. Pre-Program Communication

Suggested message to introduce CCSF: *Customers First—New Benefits for Energy Supply;*

Or for renewable energy: *It's More Than Green Power—New Benefits for Energy Supply.*

Another option could be: *More Than Individual Benefits—New Options For Essential Energy Service*

Or a third Option: *Customer- Based Energy Services—By Customers—For Customers—The Best Service For What You Need*

Or a fourth option that would work with the addition of services in addition to electricity: *New Services—New Options—Customer-Based Energy.*

1.11.2. Start-Up and Enrollment

Suggested below are options for first two notification letters. These are intended as examples only. The letters cover the primary aggregation program features. More specific and effective messages can be developed once the CCSF program is defined and the electricity product to be offered is identified and agreements with the ESP and PG&E are in place.

The first notification letter: ***Announcing Your Opportunity for Energy Benefits . . . Community Choice . . . Your Choice***

Or as a second option: *Announcing Customer-Based Energy Benefits. . . Community Choice . . . Your Choice*

Or in the case of a renewable energy mix product: *It's More than Green Power. . . Community Choice . . . Your Choice*

Sub message: Electric customers have a choice. This letter provides a general introduction to the CCSF opportunity for individual and cumulative benefits. The front page describes an easy entry to CCSF electric service. It includes a statement about the nature of benefits; a description of how delivery of benefits has been made as simple as possible; how to take advantage of the benefits; or how to choose to opt-out. Depending upon how CPUC rules and ESA terms are ultimately worked out, the letter may need to address the process and terms for exiting the CCSF program. It also includes a telephone number for more information from the CCSF customer care center. The backside of the page contains more detailed information on the CCSF; a comparative benefits chart; and a summary of the terms and conditions of service [sample terms]. [Actual terms and conditions language obviously cannot be set until an ESA is in place; CPUC and PG&E will likely want a close review of any required language]. (See Sample Letter #1 at section 4.1)

The second notification letter: Taking ***Advantage of Community Choice . . . Your Enrollment for Customer Benefits Is About To Begin***

Or as a second option: *Watch The Benefits Add Up . . . Your Enrollment for Green Power Is About To Begin*

Sub Message: For the first time electric customers have a choice. This letter repeats information from the first letter. The front page describes the easy entry to CCSF electric service. It again includes a statement about the nature of benefits; a description of how delivery of benefits has been made a simple as possible; the fact that the customer will be enrolled at the end of the next bill; or can choose to opt-out. Depending upon how CPUC rules and ESA terms are ultimately worked out, the letter may need to address the process and terms for exiting the CCSF program. The front page includes a telephone

number for more information from the CCSF customer care center. The backside of the page repeats the detailed information on the CCSF; a comparative benefits chart; and a summary of the terms and conditions of service [sample terms]. (See Sample Letter #2 at section 4.1)

1.11.3. Post-Enrollment and Operation

Suggested messages of the Post-Enrollment letters:

The third notification letter: ***Taking Advantage of Community Choice . . . You Are Now Enrolled for Customer Benefits***

Or as a second option: *Taking Advantage of Community Choice . . . You Are Now Enrolled for Green Power*

Sub Message: Congratulations for taking advantage of the benefits from "Community Choice." This letter welcomes the CCSF customer. It repeats required information from the first and second letters. The front page describes the easy entry to CCSF electric service. It again includes a statement about the nature of benefits; a description of how delivery of benefits has been made a simple as possible; the fact that customers can still change their minds and choose to opt-out. Depending upon how CPUC rules and ESA terms are ultimately worked out, the letter may need to address the process and terms for exiting the CCSF program. The front page includes a telephone number for more information from the CCSF customer care center. The backside of the page repeats the detailed information on the CCSF; a comparative benefits chart; and a summary of the terms and conditions of service [sample terms] and with a focus on rescission of enrollment. (See Sample Letter #3 at section 4.1)

The fourth notification letter: ***Taking Advantage of Community Choice Benefits . . Looking Forward To Serving You***

Or a second option for a renewable energy mix product might be: *Taking Advantage of Community Choice Green Power . . . Looking Forward to Serving You*

Sub Message: Congratulations for taking advantage of the benefits from "Community Choice." This letter repeats the welcome of the third letter to the CCSF customer. It repeats required information from the first, second and third letters. The front page describes the easy entry to CCSF electric service. It again includes a statement about the nature of benefits; a description of how delivery of benefits has been made a simple as possible; the fact that customers can still change their minds and choose to opt-out. Depending upon how CPUC rules and ESA terms are ultimately worked out, the letter may need to address the process and terms for exiting the CCSF program. The front page includes a telephone number for more information from the CCSF customer care center. The backside of the page repeats the detailed information on the CCSF; a comparative benefits chart; and a summary of the terms and conditions of service [sample terms] and with a focus on rescission of enrollment. (See Sample Letter #4 at section 4.1)

1.11.4. Established Program Operation

The established program could utilize an extension of the notification messages consistent with the central theme: *Taking Advantage of Community Choice Benefits . . . It's Our Pleasure to Serve You.*

A second option could be: *Taking Advantage of Community Choice Green Power . . . It's Our Pleasure to Serve You.*

ESA renewal could utilize a similar extension of the notification messages consistent with the central theme: *Taking Advantage of Community Choice Benefits . . . We Hope To Continue To Serve You.*

Throughout established program operations, both direct and indirect benefits achieved through the CCSF should be communicated to customers to support key themes and messages through media and targeted direct mail. To the extent that other services, such as renewable energy, or energy efficiency are incorporated into the CCSF program, or reliability, or quality of service or environmental protection gains are achieved, these should be prominently noted and communicated.

1.12. Summary of Suggested Actions

Suggestions for actions are offered under the assumption of providing only core activities for communications. The three general categories of activities are: outreach and education of customers; development and oversight of the notification and enrollment process; and oversight of a media program.

There are ten suggestions noted below related to these activities.

1.12.1. Initiate Outreach and Education Activities

As noted in section 1.2.1, initiating a round of meetings with customer groups, business and civic organizations, and community leaders to explain the CCSF and its goals would be important to establish support for the program prior to BOS discussion of the *Draft Implementation Plan* and initial media coverage. Meetings could also take place with editorial boards and reporters to provide background. Coincident with this activity, a plan for information mailings to key customer groups could be developed and implemented.

1.12.2. Formulation of Communications Plan

As noted in section 1.2.2, following BOS approval of the *Draft Implementation Plan,* it would be advisable to formulate a detailed Communications Plan and a timeline based on CPUC approval of the CCSF *Draft Implementation Plan* and CPUC rules and policies concerning CCSF implementation. This Communications Plan could include an integrated

mix of tasks related to news media and advertising that would complement a parallel Marketing and Sales Plan with actions to be carried on by a separate task group. The general purpose of the media portion of the communications program should be to promote the themes and messages to: 1) create general public familiarity with the CCSF and its purpose and base in "benefits and service"; 2) provide context and substance for events concerning the CCSF; 3) provide background and alerts for customer direct mail notifications; 4) market the program and provide education on energy issues and options and choices each consumer can make to save or use energy.

1.12.3. Establishment of Enrollment Process

The communications staff would play an important role in development of the four notification letters and the process and timeline for enrollment of customers. Establishment of a coordinating committee consisting of CCSF, ESP and PG&E staff to carry out integrated tasks for enrollment and to test the enrollment system prior to operation is strongly advised.

1.12.4. Organizational Structure Suggestions

As noted in section 1.7, the organizational structure for the communications program would follow the primary responsibilities for the services of the CCSF. For the Communications Program specifically, the CCSF would have the lead role in media and customer communications. The Communications Program would oversee the customer notification process and customer education. Communications staff would also work to assure consistency of ESP and PG&E customer education and advertising, and with the Marketing and Sales staff monitor customer care functions. Communications staff would answer directly to CCSF executive management. At an administrative level, communications staff should participate in the development and implementation of program strategy decisions, and shape the messages resulting from those decisions. Communications staff would be important participants in a coordinating committee with the ESP and PG&E.

1.12.5. Staffing Suggestions

As noted in section 1.8, Pre-Program Phase I communications activities may be Accomplished with only one full time communications staff position and consultant support, if there is not extensive activity. However, a full communications program would require a minimum of one full time communications supervisor, and one full time senior communications manager, plus one part-time administrative assistant position. This level of need would continue through to Established Operations.

1.12.6. Estimated Budget

The draft estimated budget is based on minimum staff focused on core activities. The draft estimate will need to be refined as part of the review of section 1.7 activities and assumptions concerning overlapping or shared responsibilities with other CCSF staff and

staff compensation, as well as the development timeline. The estimated budget would also need to be reviewed for the notification mailing costs assumed, and the level of the advertising budget, and the levels of contingency accounts.

The draft estimate is $1,083,875 for Pre-Program Communications through Post-Enrollment (including the 15 percent contingency). More than 54 percent of estimated costs in the budget are for notification mailings. Approximately 20 percent is for Media/Advertising. And approximately 25 percent is for communications management and customer care [including both staff and consultants.]

The draft estimate for Established Program Operations is $342,240 annually (including the 15 percent contingency). Approximately 40 percent of the direct costs are for on-going monthly notification mailings for new customers. Approximately 20 percent is for Media/Advertising. Approximately 40 percent is for communications management, enrollment oversight, and customer care monitoring.

1.12.7. Funding

The goal of the CCSF program should be self-support through ESP contributions to Advertising, notification, enrollment and public education expense and program revenues. This can be achieved once enrollment has occurred and revenue is flowing from customers. For at least the Pre-Program stage and part of the Start-Up activities, however, CCSF funds will need to be budgeted and utilized. For the communications program, Pre-Program and other funds not directly reimbursed by the ESP should be covered by part of a small kilowatt-hour operational charge.

1.12.8. Media Choice

The choice of media should include a standard mix of print, electronic, and direct mail, or e-mail, to target groups. A common method of utilizing overlapping and repeated themes and messages scheduled to specific stages of the CCSF development should be utilized. Determination of specific media choices will depend to a large extent on the formulation of a Communications Plan noted in section 1.2.2 and the approved media budget. Press events and Public Service Announcements (PSAs) in print media, radio, and television should be used as frequently as possible to reduce costs.

1.12.9. Key Theme Suggestions

The supporting or background theme could emphasize, “electricity is an essential service.” This would resound with consumer experience, and provide a simple yet powerful basis for why the CCSF has been established. Coupled with this, the concept that “consumer benefits are possible through bulk power purchase” could be utilized.

The central foreground theme for the CCSF throughout all stages of development could be that of securing and delivering benefits to SF residents and businesses—providing “benefits and service”—in shorthand notation.

In addition to conceptual themes and messages, a single attractive graphic image could be created to symbolize the program. Other attractive graphics could be created and utilized in posters [for which there could be public competitions].

The background and foreground themes should be tested as part of the Communications Plan development and reflected in messages at each stage to form a consistent overlapping message stream.

1.12.10. Timeline

The timeline for communications will be determined by four key events: 1) the SFBS approval of the CCSF Plan; 2) the CPUC approval of the CCSF Plan and CPUC determinations concerning project start-up; 3) execution of an ESA with a supplier; 4) the chosen enrollment date. The Pre-Program Communications period offers flexibility for preparation of the program prior to the start of these events.

[See Appendix section 4.1 General Timeline for detail on initiation of activities related to key events.]

2. Short Term Plan Implementation

2.1. 2.1 Overview

Section 1 above offers an outline of chronological development for the communications program and general description of activities, structure and staffing.
Section 2 addresses specific communications implementation issues and tasks that may be considered in the Pre-Program to Post Enrollment activities.

Section 2 emphasizes the need for a team approach—coordination of CCSF, PG&E, and ESA staff—to successfully undertake start-up and initial enrollment activities and the communications related to those activities. It also discusses in more detail public education and outreach to specific customer groups. It provides additional information on the notification, enrollment and opt-out process, including phased customer notification and enrollment. Activities for integration of energy efficiency and other services may also be undertaken in the short term, and if so, communications related activities for those developments would need to be incorporated in the Short Term activities. However, for purposes of the discussion below, those considerations are deferred to the Long Term Plan discussed in section 3.0.

2.2. Pre-Program—Reaching Customer Groups

2.2.1. Phase I: Initial Pre-Program Communications Activities

Phase I activities should establish the conceptual basis for the program. This can be

accomplished through outreach to key groups prior to public media. Discussion with these key groups may help to shape messages to be offered. There are a variety of methods to conduct this outreach, for example:

- Meetings/Presentations—critical customer groups and associations could be identified and meetings and presentations scheduled with those groups to explain the goals, process, the anticipated schedule for the CCSF program, and the specific benefits to be offered. These meetings could be informational only, or efforts could be made to gather letters of support, or endorsement of the CCSF program.

- Target Mailings—target mailings can be used in conjunction to meetings with critical customer groups and associations, or separate from, or in follow-up to those meetings. The advantage of such mailings is the ability to emphasize and outline particular points clearly for a large group of customers. The disadvantage is the lessened level of feedback that is offered by a meeting and presentation, if such a mailing is a separate activity.

- Editorial Board Meetings—meetings with editorial boards at an early stage to explain the goals, process, anticipated schedule and specific benefits could be undertaken to prepare the press for press releases that will be issued concerning key events (i.e. presentation and BOS CCSF Draft Implementation Plan review). Such meetings may also help to identify specific reporters or editors who will follow the story, if they are not known already.

- Initial Editorials/Initial Articles—meetings with Editorial Boards could seek support or endorsement of the program; they may also assist in scheduling more in-depth background time with specific reporters in advance of events; or to schedule time for appearances on radio or television talks shows to explain the CCSF program. These activities would be expanded as part of a Communications Plan in Phase II.

2.2.2. Phase II: Advanced Pre-Program Communications Activities

As noted in section 1.2.2, the second phase of Pre-Program Communications could commence with BOS approval of the CCSF *Draft Implementation Plan* (including a communications component) and adoption of a budget for program communications. This would allow planning and launch of a formal communications effort. The second phase would include:

- Develop Communications Plan—formulation of a detailed Communications Plan which would likely be created in draft form and then final form with a timeline based on California Public Utility Commission (CPUC) approval of the CCSF *Draft Implementation Plan*

and CPUC rules and policies concerning CCSF implementation. This Communications Plan would include work with news media and advertising strategies and schedules. The general purpose of the media portion of the communications program should be to promote themes and messages to: 1) create general public familiarity with the CCSF and its purpose and base in "benefits and service"; 2) provide context and substance for events concerning the CCSF; 3) provide background and alerts for customer direct mail notifications; 4) market the program and provide education on energy issues and options and choices each consumer can make in saving or use of energy. It would be utilized during Start-Up, Enrollment, and Post-Enrollment periods. An early portion of the Communications Plan can also be utilized during Phase II activities and include a press conference on BOS approval of the CCSF Plan and press releases for CPUC determinations and issuance of an RFQ or RFP for power supply.

- Press releases and communications activity on benchmark events could include:
  BOS Approval of CCSF Plan
  CPUC Approval of CCSF Plan
  Issuance of RFQ or RFP
  Response or Result of RFQ or RFP
  Execution of Electric Supply Agreement
  Mailing of Notification Letters
  Start-Up of Enrollment
  Completion of Enrollment
  Other Services Offered (when and if offered)

- Advertising—prepare and schedule advertising/posters/flyers, etc. as determined in advertising portion of Communications Plan.

- Meetings and presentations—the schedule of meetings and presentations and appearances on talk shows could be continued and expanded during the Phase II Pre-Program period, and beyond through the benchmark events.

2.3. Start-Up—Preparing the Opt-Out Process

As media efforts are increased, customer care representatives will find an acceleration of public questions beginning with the signing of the ESA. A timeline and schedule for coordination will need to be developed. Start-Up could commence with the execution of an Electric Supply Agreement (ESA) [or a Day 0 resulting from schedule determinations of the CPUC]. It would consist of simultaneous activities for: expansion of the media program; coordination between PG&E, ESP and CCSF to develop an integrated customer care program; and coordination between the Pacific Gas and Electric (PG&E) and the ESP and CCSF to prepare the enrollment process.

The Start-Up schedule will be driven by both statutory requirements and rules and policies established to implement those requirements.

For the purposes of preparing a successful notification and opt-out process as required by law, a coordinating committee consisting of selected members of the CCSF, ESA, and PG&E will need to be convened. The coordinating committee could meet weekly and continue with timely communications among specific members on a daily basis. The committee would manage the agreed upon tasks shared among the three parties. Among the elements that would need to be addressed by the committee:

- Review of tasks and responsibilities and designation of specific contact persons for specific functions
- Development or designation of a CCSF Web Page for the Program (managed by the City or the ESA);
- Integration of links from PG&E Web Page to CCSF web page and ESA web page;
- Development of a CCSF customer call center/ with standard script for FAQ and agreement on types of referrals to PG&E and the ESA;
- Integration with utility customer call center and sharing of script information and electronic referral process to CCSF customer call center (which could be a telephone number or direct line switch);
- Weekly (or more frequent) monitoring of customer questions and problems in coordination of customer communication;
- Preparation and timing of the Enrollment Process, including integrated IT testing and review of notification materials

2.4. Enrollment—Managing Chaos

Management of the enrollment process would be the first public function of the CCSF program and it is important that it operate as smoothly as possible. It would include tasks for oversight of mailhouse (or PG&E) activities for notification mailings; oversight and operation of the customer call center, and IT functions for enrollment. The tasks need to be fully prepared and the system organized in an integrated manner to meet the challenges of the number of customer notifications and enrollments to be undertaken. The process also needs to be managed to meet statutory and regulatory rule requirements on the timing of notifications and enrollment.

Mailhouse functions and notification activities will depend in part on whether mass enrollment is required, or phased-in enrollment is allowed. While section 1.4 focuses on notification and enrollment of a single mass group for purposes of discussion, if rules allow a phase-in of customer enrollments, this would allow the potential magnitude of customer questions and problems to be better managed, reducing the number of staff needed, and improving response and problem resolution time. This would help to enhance general customer satisfaction at the outset of the CCSF program.

Phasing of customer notification and enrollment could occur by neighborhood, or by rate code. Rate code phase-in could be the preferred method, allowing more specific notification letters and information to be sent to each customer class. Information of particular interest to business customers could be emphasized for commercial code notification mailings; information of interest to residential customers could be emphasized for residential code notification mailings. Specific customer service telephone numbers could also be provided, with one set of customer service representatives addressing commercial questions with a prepared script; and a similar process specifically for residential customers. If phase-in occurred by neighborhood, it could offer an advantage for penetration of local media, posters, and meetings with key organizations in a specific area. This could prove more effective than rate code phase-in for residential areas; while rate code phase-in could be more effective for commercial customers.

If phase-in of customer notification and enrollment is not allowed by the rules, adequate staffing will be required and a referral system for calls from specific rate code customers to customer service representatives trained and scripted for that customer code.

As noted in section 1.4.3, a tracking system needs to be in place for customers who choose to opt-out of enrollment in the CCSF program. The opt-out period could continue for 30 days [or interval determined by CPUC] following the mail date of the second notification. On a rolling basis, or on completion of the opt-out period, the mail house could gather the recorded and returned opt-out cards for removal of these customers from the prepared enrollment list. [If opt-outs have also been gathered via telephone requests, CCSF customer care representative would transmit written records of telephoned oral opt out requests that should also be extracted from the enrollment list.] The notifications returned as undeliverable would also be removed from the enrollment list.

The IT enrollment process needs to be fully tested to meet anticipated daily transfer and intake of customers, and timely communications and management of both generic and individual enrollment problems. As noted in section 1.4.4, the process for setting up and managing enrollment should be accomplished with the Start-Up activities in section 1.3.3. The system should also be tested during Start-Up (section 1.3.3) or during the Customer Care Start-Up (section 1.4.1) activities. With the process set up and tested, enrollment can proceed.

Assuming a maximum customer base of approximately 353,000 customers, and enrollment proceeding over a 21-day cycle of billing reads, the enrollment process would need to transfer on average approximately 16,800 customers per day to the ESP. The actual daily number may be higher or lower, depending upon PG&E meter-read and billing schedules. The number of opt-outs and undeliverables removed from the customer base will also affect the average daily number of enrollments. As previously noted, if phase-in of customer groups is allowed, the number of customers being notified and enrolled would be lower. This would take more time, but ease burdens on the customer care and IT system and allow for a more specific focus on customer types.

In general, throughout the notification and enrollment process, timely communications between coordinating committee members and designated staff is critical. Timely communications would increase the ability to address all aspects of notification and enrollment problems on a daily and weekly basis through a planned schedule of conference calls and as-needed individual contacts. Effective internal communication would increase the effectiveness of customer care, especially for customers facing individual or generic problems.

As noted in section 1.3.2, early start-up of Customer Care could commence following the announcement of execution of the ESA and customer representatives be prepared to answer general questions on the CCSF, pricing of power supply, the enrollment and opt-out process, and the ESP. This function would increase over time with customer responses to additional news articles or news features, advertising and mailings, and notification mailings. The official start-up of a customer call-in center would take place just prior to the first notification mail drop, and be aimed specifically at responding to customer questions on the mailing. Communications staff must be part of this process. The bulk of this work will follow through the fourth notification, although staffing may be moderated based on call response. Following the notification period, the customer call-in center would be staffed at established operational levels based on anticipated call volumes.

2.5. Post Enrollment—Focused Customer Care

Successful customer care—either as general customer communications, or communication and problem solving for a specific customer—is essential to the CCSF program. The first step in this process is making sure customers are educated about the enrollment and opt-out process. The second step is identifying generic problems and solutions and communicating those on a timely basis with customer care representatives. Individual problems could take more time to resolve, and in all of these cases, the involvement of Marketing and Sales representatives may help to speed the process. Media work by the communications staff could also help to remedy any customer confusion that results in generic problems. Specific customer care can be enhanced if a customer care representative can be assigned to a single customer rate code group, and become familiar with the concerns, problems, and resolution of issues specific to that group.

Each notification mailing will result in a certain number of mail pieces returned as undeliverable due to problems with the address, or the fact that the customer has moved and may or may not be within the service territory. A review should be made (by comparison to an updated customer list from PG&E) to determine which addresses to correct and re-mail and which ones to eliminate. As part of the schedule for integrated enrollment work with PG&E, delivery of such an updated list should be included for a specific date. A process to have returns read and held by the mail house, and the updated list to be transferred for address corrections, and re-mailed should also be arranged.

The updated customer list from PG&E will also indicate new customers who have entered the service territory between the time the first list was pulled and processed for mailing, and the final opt-out notice. A "catch-up" mailing of the four required notifications should be

started for these new customers. While this "catch-up" could be started at the time of the second mailing, holding the "catch-up" for a batch mailing could allow a more coordinated approach. If a single notification mailing, rather than four notifications, is allowed for the "catch-up" group, the letter and process could follow the example of the "refresher" mailing noted in section 1.5.3. The use of phase-in enrollment for the implementation of the CCSF program [if allowable] would complicate the "catch-up" process by creating more "catch-up" groups. These groups could be held and batched for a single mailing, although time delay would be a factor for consideration.

3. Long Term Plan Implementation

3.1. 3.1 Overview

The CCSF program will undoubtedly face a range of challenges following implementation and initial operation. Some of those challenges may relate to expansion of the program to provide energy efficiency, natural gas, or other services. Other challenges may result from changes in electric market structure, changes in regulatory rules, or increased competition. Additional challenges may result from changes in technology over time that open new program opportunities.

While initial goals of the communications program would be to educate customers and support establishment of the program, a longer-term goal might be to solidify trust with consumers for customer retention and to achieve a role as a preferred source of information regarding the energy services industry.

To achieve this, a service organization such as CCSF relies upon its history of operation and its outlook in the marketplace. An effective Communications Plan cannot substitute for service benefits, sound strategies, effective participation in policy-making, or reliable service delivery. But because it is a non-profit public entity carrying public accountability, the CCSF has a great opportunity to build public trust. It is important therefore to assure that the quality and benefits of CCSF operation are communicated to public officials, consumers and the industry in the most effective manner. Beyond this internal focus, it is also important that an understanding of industry and market trends are effectively communicated to the media, consumers and public officials This means keeping up with or staying ahead of the curve on industry developments and understanding how they will influence consumers and the CCSF program.

3.2. 3.2 Challenges—Changes in Markets, Rules, Expectations

Two types of potential long-term challenges exemplify the anticipation and preparation required in a successful long term Communications Plan.

The first type of challenge is a change in the market in which the CCSF offers new services—the challenge of an expanding program—such as addition of energy efficiency services or natural gas supply. This would require re-orienting messages to cover both individual services and value of integration of services. It may also require, on a temporary

basis, the need for additional staff, or close integration with marketing and sales staff. Depending on the type of service or benefits, the model of a pre-program, start-up, enrollment and post-enrollment communications effort described in Section 1 might be utilized.

The second type of challenge is generated externally, rather than by expansion of the program. This challenge could arise from changes in the electric supply market, or rules concerning the market and competition. This is much more difficult to manage.

While wholesale electric supply markets have broadened and regulation is maturing, the wholesale level is likely to remain subject to volatility related to fuel pricing and seasonal demand and supply events. Retail markets can suffer from the volatility of wholesale markets. Changes in pricing can make an ESA producing savings in the short term, suddenly appear to be a higher cost alternative for customers. The original expectations of customers can change, and customer retention could become a significant challenge posing impacts across the customer base.

In addition, due to the fact that retail markets are at an earlier stage of development, retail markets can also be affected by changes in market rules and structure. For example, the current lack of retail competitors could be changed by alterations in rules or law that allow the emergence of new retail suppliers focused on acquiring medium and large commercial customers. If the CCSF finds other entities preparing to compete for customers within its selected market niche, the CCSF would need to engage both strategy and communications to address this development. If head-to-head competition at existing terms is not advisable, the CCSF might choose to offer additional benefits or services that enhance continued customer participation in the CCSF.

An effective communications plan needs to anticipate, in outline form at the least, what likely challenges could be anticipated, and what the best responses to those challenges would be and what the responses will require.

3.3. Program Adjustments For A Sustainable Communications Program

There are four areas that might be considered for a sustainable communications program that helps build customer trust and long term CCSF support.

3.3.1. Enhanced Customer Communications

Direct communications with existing customers to build a relationship of trust could be utilized in a number of overlapping forms. If the communications budget allows—a periodic newsletter (in hard copy and electronic format) should be prepared that will communicate CCSF developments and offer customers new ways to save and create environmental benefits through energy efficiency and renewable energy production or use. Direct mailings to commercial customers, or customers in neighborhoods with specific problems might also be useful; periodic meetings and presentations for commercial customers, or civic groups would be beneficial. To the extent possible, the "message line"

on the utility bill should also be utilized for communications with CCSF customers; judicious use of web mail messaging to specific customer groups might also be utilized. Cooperative arrangements for mailing or insertion of additional mailed information might also be accomplished through other City service departments, in cases where complete coverage is not necessary.

3.3.2. On-Going Media Communications

To augment and reinforce direct customer communications, development of regular or periodic columns in news media; periodic appearances on television and radio shows; advertising; or development of a special program video (or multiple videos) for use with public media stations, schools, and business and civic groups, would be useful at broad mass market level. These media communications could include information to help customers understand particular benefits, or understand the broader trends in the industry and the comparative benefits of various options or choices they may face in the future.

3.3.3. Internal Communications

It is also important to keep common messages and cooperation in customer inquiry referral updated among the ESP, PG&E, and CCSF. The types of questions and responses may change over time, and established contacts and periodic meetings to track any coordination or information problems should be on going.

3.3.4 On-Going Enrollment Functions

Retaining customers is a function of both the service products offered and communications concerning the products and resulting customer expectations. Each of the enrollment communications should be viewed as an opportunity for inclusion of information on specific service produce inserts, or a customer newsletter. A "welcome kit" provided by the ESP would provide an additional opportunity to include these additional CCSF communications. From the outset of enrollment the customer could be provided with information on specific benefits of present services, and a sense of trends and what may lie ahead.

3.4. Structure, Staffing, Budgets

Evolution of markets or services or technology may require changes in operational structure, or how the parts of the operational structure interact. As noted above, the coordination of ESP, PG&E and CCSF for up-to-date and accurate customer information may require changes from time to time. In addition, a staff consisting of one full time communications supervisor and one full time senior communications manager, plus one part time administrative assistant, could be insufficient during periods when challenges are emerging, or new services are being prepared and offered. Reserve funds included in the estimated budget could be utilized for meeting the demands of temporary staff expansion and additional spending, and depending upon the magnitude of the challenge, additional funds from the CCSF may be needed. Depending upon the terms of the ESA, or upon

business interests, the ESP may have an interest in providing additional funding to meet emerging challenges to CCSF services.

3.5. Summary of Long Term Implementation Suggestions

As noted above, communications challenges after the CCSF program has been established can result from expansion of services, changes in the market, changes in rules and competition, and changes in customer expectations. An effective communications plan needs to anticipate, in outline form at the least, what likely challenges could be anticipated, and what the best responses to those challenges would be and what the responses will require. A communications program that can effectively build trust with customers, and that educates customers on anticipated trends and changes would provide essential support for the CCSF.

In addition to the core functions of the communications program to help establish the CCSF, four areas described above could receive consideration for additional development: enhanced customer communications, on-going media communications, internal communications, and on-going enrollment functions.

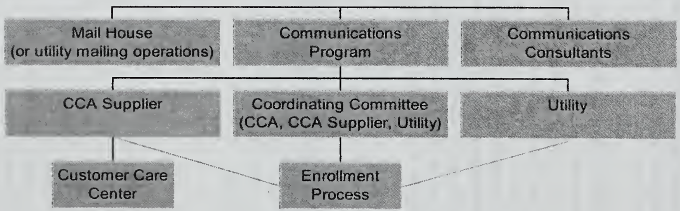
While the activities of the core communication program functions might be carried out by the two full time positions and one part time position described, additional staffing might be required to meet demands for expanded services or emerging challenges. The budget for this expansion could come from reserve funds in the estimated budget, or from additional funds from the CCSF general budget, or contributions from the ESP, or some combination of those sources.

4. Appendices

4.1. Organizational Chart, Estimated Budget, General Timeline
4.2. Sample Notification Letters (4)
4.3. Sample FAQ Sheet

(SEE FOLLOWING PAGES)

CCA COMMUNICATIONS
Organizational Chart



CCA COMMUNICATIONS PLAN

Draft Budget Estimate

			Subtotals
Pre-Program			
Phase I	60,000		
Phase II	90,000		
			150,000
Start-Up			
Media	60,000		
Coordination	35,000		
Enrollment Preparation	25,000		
			120,000
Enrollment			
Customer Care	15,000	20,000	
Notification Mailings	122,500	122,500	
IT Enrollment Process		15,000	
Media/Advertising	40,000	40,000	
			375,000
Post Enrollment			
Notification Mailings	122,500	122,500	
Catch-Up Mailings		15,000	
Monitoring Customer Care		2,500	
Media/Advertising	20,000	10,000	
Preparation for Refresher		5,000	
			297,500
SUBTOTAL			942,500
Contingency (15%)			141,375
TOTAL			**1,083,875**
Established Operations			
Media/Advertising	5,000/month		

COMMUNICATIONS PLAN General Timeline

	Day -180	Day -120 to 0	Day 0-150
Pre-Program			*(Actual Day 0 will begin bas*
Phase I	Activities 1.2.1	Continue 1.2.1 activity	
Phase II		Activities 1.2.2 begin with SFBS approval on CCA Communications Plan and budget	
Start-Up			
Media			Activities 1.3.1 begin with ES
Coordination			Activities 1.3.2 begin with ES
Enrollment Preparation			Activities 1.3.3 begin with ES

	Day 0-90	Day 30	Day 90-120	Da
Enrollment				
Customer Care	Activities 1.4.1 begin coincident with articles/advertising from 1.3.1 activity			
Notification Mailings		Activities 1.4.2 begin with first mail drop		
IT Enrollment Process			Activities 1.4.3 followed by 1.4.4 begin	
Post-Enrollment				
Notification Mailings				Act
Catch-Up Mailings				Act
Customer Care Mon.				Act
Refresher Mail Prep.				Act
Program Operation				
Established Operations				

SEE INDICATED REPORT SECTIONS FOR DESCRIPTIONS OF ACTIVITIES

SAMPLE NOTIFICATION LETTER #1
City of San Francisco
Community Choice Electricity (GRAPHIC)

FOR TRANSLATION SERVICES: Espanol: (415) xxx-xxxx
Chinese: (415) xxx-xxxx Vietnamese: (415) xxx-xxxx Etc……..

Announcing Your Opportunity for Energy Benefits . . . Community Choice . . . You're Choice.

Dear San Francisco Electric Service Customer:

For the first time electric customers have a choice in their electric supply. Based on positive experience in other regions, the City of San Francisco has negotiated a contract for electricity for residents and businesses. This is known as "Community Choice." You will have the opportunity to take advantage of the resulting energy benefits.

Here's what the electricity contract will provide: [describe benefits of electricity product offered for XX months.] (See reverse side for more details on benefits and terms and conditions of service.)

Delivery of these benefits is designed to be as simple as possible. You will still receive your monthly bill from the electric company. You will continue to have the same level of service and reliability. You will still make your monthly payment to the electric company and they will continue to read your meter and provide all of the services for distribution of electricity. Only the source of the energy noted on your electric bill will change.

Taking advantage of these energy benefits is easy. If you wish to participate, you do not need to take any action. You will be automatically enrolled. If you do not wish to remain with PG&E electric supply, all you need to do is sign and send in the enclosed opt-out card. [or phone if CPUC provides taped oral opt-out option] The choice is yours.

If you choose to take advantage of these energy benefits, you will receive three more letters during the next few months outlining progress in your enrollment for Community Choice electric supply. You can leave the Community Choice electric supply at any time with no penalty. [Based on rules and ESA state primary conditions for opt-out after being enrolled.]

Because this is a new option for electric supply, we have included more details on the reverse side of this letter. You can also call us with questions at: (415) XXX-XXXX.
Or visit the Community Choice website at: www. xxxxxxxxxxx. Xxx

We look forward to serving you with the energy benefits Community Choice can offer.

Sincerely,
[Signature]

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION)

Community Choice Electricity

Background on Community Choice Aggregation

The option for Community Choice electric supply was authorized by the state government on September 24, 2002. San Francisco's Community Choice Plan was approved by the California Public Utilities Commission on [insert date] and the electric supply contract was approved by the San Francisco Board of Supervisors on [insert date].

In addition to providing direct benefits, the Community Choice program can help to enhance consumer protection. It can also be integrated with services for energy efficiency, renewable energy development and pollution reduction. These are important features that contribute to your energy security and protect public health and welfare.

As already noted, taking part in the program is designed to be easy. You do not need to take any action to participate. You will be automatically enrolled. If you do not wish to participate, simply sign and mail in the enclosed opt-out card. [or phone if CPUC offers taped option]

For additional information on San Francisco's Community Choice Aggregation see: [website]
For additional information on electric industry restructuring in California see: [website]
For additional information on national issues in electric industry restructuring see: [website]

Community Choice Benefits (chart)

[Need to note residential/commercial benefits—and comparative PG&E benefits]
[Set up in chart with term/years if that increases clarity]
[Include notes on possible CCSF and PG&E terms, if any—refer to terms and conditions]

Terms and Conditions of Service (these need to be resolved with supplier and PG&E]

As previously noted, only the source of electric energy noted on your electric bill will change.
Eligibility: Customer service address must be in San Francisco
Opt-out terms: [Will depend upon ESA terms and CPUC rules regarding penalties and timing]
Standard conditions and terms of service for the electric company continue to apply to participants in Community Choice service.
Payment of monthly bills: Bills must be paid [terms for payment]
Credit required: [commercial customers]
Shutoff by electric company for non-payment: [continue current rules and regulations]
Budget Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Automatic Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Low-Income Consumers: [need to examine electric company discounts and policies]
Other Customer Discounts: [i.e. non-profit customers—need to examine]

SAMPLE NOTIFICATION LETTER #2
City of San Francisco
Community Choice Electricity (GRAPHIC)

FOR TRANSLATION SERVICES: Espanol: (415) xxx-xxxx
Chinese: (415) xxx-xxxx Vietnamese: (415) xxx-xxxx Etc……..

Taking Advantage of Community Choice . . . Your Enrollment for Customer Benefits Is About To Begin

Dear San Francisco Electric Service Customer:

For the first time electric customers have a choice in their electric supply. Based on positive experience in other regions, the City of San Francisco has negotiated a contract with energy benefits for electricity for residents and businesses. This is "Community Choice."

Here's what the electricity contract will provide: [describe benefits of electricity product offered for XX months]. (See reverse side for more details on benefits and terms and conditions of service.)

Delivery of these benefits is designed to be as simple as possible. You will still receive your monthly bill from the electric company. You will continue to have the same level of service and reliability. You will still make your monthly payments to the electric company and they will continue to read your meter and provide all of the services for distribution of electricity. Only the source of the energy noted on your electric bill will change.

Taking advantage of these energy benefits is easy. If you wish to participate, you do not need to take any action. You will be automatically enrolled at the end of your next bill. If you do not wish to participate, all you need to do is sign and send in the enclosed opt-out card. [or phone if CPUC provides taped oral opt-out option] The choice is yours.

If you choose to take advantage of the energy benefits, you will receive two more letters during the next few months following your enrollment that will state the terms and conditions of service and offer you an opportunity to remain with PG&E electricity supply. You can leave the Community Choice program at any time with no penalty. [Based on rules and ESA state primary conditions for opt-out after being enrolled.]

Because this is a new option for electric supply, we have included more details on the reverse side of this letter. You can also call us with questions at: (415) XXX-XXXX.
Or visit the Community Choice website at: www. xxxxxxxxxxx. Xxx

We look forward to serving you with the benefits Community Choice can offer.

Sincerely,
[Signature]

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION)

Community Choice Electricity

Background on Community Choice Aggregation

The option for Community Choice electric supply was authorized by the state government on September 24, 2002. San Francisco's Community Choice Plan was approved by the California Public Utilities Commission on [insert date] and the electric supply contract was approved by the San Francisco Board of Supervisors on [insert date].

In addition to providing benefits, the Community Choice program can help to enhance consumer protection. It can also be integrated with services for energy efficiency, renewable energy development and pollution reduction. These are important features that contribute to your energy security and protect public health and welfare.

As already noted, taking part in the program is designed to be easy. You do not need to take any action to participate. You will be automatically enrolled. If you do not wish to participate, simply sign and mail in the enclosed opt-out card. [or phone if CPUC offers taped option]

For additional information on San Francisco's Community Choice Aggregation see: [website]
For additional information on electric industry restructuring in California see: [website]
For additional information on national issues in electric industry restructuring see: [website]

Community Choice Benefits (chart)

[Need to note residential/commercial benefits—and comparative PG&E benefits]
[Set up in chart with term/years if that increases clarity]
[Include notes on possible CCSF and PG&E terms, if any—refer to terms and conditions]

<u>Terms and Conditions of Service (these need to be resolved with supplier and PG&E]</u>

As previously noted, only the source of electric energy noted on your electric bill will change.
Eligibility: Customer service address must be in San Francisco
Opt-out terms: [Will depend upon ESA terms and CPUC rules regarding penalties and timing]
Standard conditions and terms of service for the electric company continue to apply to participants in Community Choice service.
Payment of monthly bills: Bills must be paid [terms for payment]
Credit required: [commercial customers]
Shutoff by electric company for non-payment: [continue current rules and regulations]
Budget Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Automatic Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Low-Income Consumers: [need to examine electric company discounts and policies]
Other Customer Discounts: [i.e. non-profit customers—need to examine]

SAMPLE NOTIFICATION LETTER #3
City of San Francisco
Community Choice Electricity (GRAPHIC)

FOR TRANSLATION SERVICES: Espanol: (415) xxx-xxxx
Chinese: (415) xxx-xxxx Vietnamese: (415) xxx-xxxx Etc……..

Taking Advantage of Community Choice . . . You Are Now Enrolled for Energy Benefits

Dear San Francisco Electric Service Customer:

Congratulations for taking advantage of the energy benefits from "Community Choice." With the close of your last bill you are now receiving electric supply the City of San Francisco has negotiated for residents and businesses.

Delivery of energy benefits is designed to be as simple as possible. You will still receive your monthly bill from the electric company. You will continue to have the same level of service and reliability. You will still make your monthly payment to the electric company and they will continue to read your meter and provide all of the services for distribution of electricity. Only the source of the energy noted on your electric bill will change.

Here's what the electricity contract will provide: [description of benefits from electricity product offered for XX months]. (See reverse side for more details on benefits and terms and conditions of service.)

As required by state law, you still have an opportunity to change your mind. If you do not wish to participate, all you need to do is sign and send in the enclosed opt-out card. [or phone if CPUC provides taped oral opt-out option] The choice is yours.

Also as required by state law, you will receive one more letter next month that will state the terms and conditions of service and offer you another opportunity to return to PG&E electricity supply. Even after that letter you may choose to leave the Community Choice electric supply at any time. [Based on rules and ESA state primary conditions for opt-out after being enrolled.]

Because this is a new option for electric supply, we have included more details on the reverse side of this letter. You can also call us with questions at: (415) XXX-XXXX.
Or visit the Community Choice website at: www. xxxxxxxxxxx. Xxx

We are very happy to serve you with the benefits Community Choice can offer.

Sincerely,
[Signature]

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION)

Community Choice Electricity

Background on Community Choice Aggregation

The option for Community Choice electric supply was authorized by the state government on September 24, 2002. San Francisco's Community Choice Plan was approved by the California Public Utilities Commission on [insert date] and the electric supply contract was approved by the San Francisco Board of Supervisors on [insert date].

In addition to providing benefits, the Community Choice program can help to enhance consumer protection. It can also be integrated with services for energy efficiency, renewable energy development and pollution reduction. These are important features that contribute to your energy security and protect public health and welfare.

As already noted, taking part in the program is designed to be easy. You do not need to take any action to participate. You will be automatically enrolled. If you do not wish to participate, simply sign and mail in the enclosed opt-out card. [or phone if CPUC offers taped option]

For additional information on San Francisco's Community Choice Aggregation see: [website]
For additional information on electric industry restructuring in California see: [website]
For additional information on national issues in electric industry restructuring see: [website]

<u>Community Choice Benefits (chart)</u>

[Need to note residential/commercial benefits—and comparative PG&E benefits]
[Set up in chart with term/years if that increases clarity]
[Include notes on possible CCSF and PG&E terms, if any—refer to terms and conditions]

<u>Terms and Conditions of Service (these need to be resolved with supplier and PG&E]</u>

As previously noted, only the source of electric energy noted on your electric bill will change.
Eligibility: Customer service address must be in San Francisco
Opt-out terms: Opt-out terms: [Will depend upon ESA terms and CPUC rules regarding penalties and timing]
Standard conditions and terms of service for the electric company continue to apply to participants in Community Choice service.
Payment of monthly bills: Bills must be paid [terms for payment]
Credit required: [commercial customers]
Shutoff by electric company for non-payment: [continue current rules and regulations]
Budget Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Automatic Billing: [need to identify whether electric company will cooperate for these customers and evaluate need to amend policies or process]
Low-Income Consumers: [need to examine electric company discounts and policies]
Other Customer Discounts: [i.e. non-profit customer--need to examine]

SAMPLE NOTIFICATION LETTER #4
City of San Francisco
Community Choice Electricity (GRAPHIC)

FOR TRANSLATION SERVICES: Espanol: (415) xxx-xxxx
Chinese: (415) xxx-xxxx Vietnamese: (415) xxx-xxxx Etc……..

Taking Advantage of Community Choice Savings . . . Looking Forward To Serving You

Dear San Francisco Electric Service Customer:

Congratulations for taking advantage of the energy benefits from "Community Choice." You are now receiving electric supply the City of San Francisco has negotiated for residents and businesses. We hope this is the beginning of many benefits Community Choice will offer.

Delivery of your energy benefits is designed to be as simple as possible. As you have probably noticed, you still receive your monthly bill from the electric company and make your monthly payment to the electric company. The electric company and continues to read your meter and provide all of the services for distribution of electricity. You continue with the same level of service and reliability. Only the source of the energy noted on your electric bill has changed.

Here's what the Community Choice electricity contract provides: [description of benefits of electricity product for XX months]. (See reverse side for more details on benefits and terms and conditions of service.)

As required by state law, you still have an opportunity to change your mind. If you do not wish to participate and receive the savings, all you need to do is sign and send in the enclosed opt-out card. [or phone if CPUC provides taped oral opt-out option] The choice is yours.

Also as required by state law, you may choose to leave the Community Choice electric supply at any time. [Based on rules and ESA state primary conditions for opt-out after being enrolled.]

Because this is a new option for electric supply, we have included more details on the reverse side of this letter. You can also call us with questions at: (415) XXX-XXXX.
Or visit the Community Choice website at: www. xxxxxxxxxxx. Xxx

We are very happy to serve you with the benefits Community Choice can offer.

Sincerely,
[Signature]

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION)

Community Choice Electricity

Background on Community Choice Aggregation

The option for Community Choice electric supply was authorized by the state government on September 24, 2002. San Francisco's Community Choice Plan was approved by the California Public Utilities Commission on [insert date] and the electric supply contract was approved by the San Francisco Board of Supervisors on [insert date].

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Terms and Conditions of Service (these need to be resolved with supplier and PG&E]

As previously noted, only the source of electric energy noted on your electric bill will change.
Eligibility: Customer service address must be in San Francisco
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Low-Income Consumers: [need to examine electric company discounts and policies]
Other Customer Discounts: [i.e. non-profit customers—need to examine]

SAN FRANCISCO
COMMUNITY CHOICE AGGREGATION
FREQUENTLY ASKED QUESTIONS

(These are the types of basic questions that can be answered once the program has been defined and a product to be offered has been identified. The FAQ sheet can be mailed out in hard copy with the notification letter and posted on the CCSF website, as well as shared with ESP and PG&E customer care representatives.)

1) What is Community Choice Aggregation?

2) Why is the City of San Francisco Offering Community Choice Aggregation?

3) What will this change? (Who will be my supplier? Will this affect my service?)

4) What are the benefits?

5) Will this cost me anything?

6) Are there risks or penalties?

7) What the other terms and conditions of service?

8) What do I need to do to participate and take advantage of the savings?

9) What do I need to do if I do not want to participate and take advantage of the savings?

10) What is the source of electricity? (Who is the power supplier?)

FOR ADDITIONAL INFORMATION: (Provide telephone contact numbers and other sources of voice or electronic information)

Community Choice Aggregation
Draft Implementation Plan

Chapter 9:
CCSF Participation in CPUC Proceedings Related to Community Choice Aggregation.

Prepared
By
The San Francisco Public Utilities Commission

Table of Contents

1. OBJECTIVE

This chapter reviews current CPUC proceedings that most directly influence the CCA decision-making for the city. These CPUC proceedings, and the CPUC itself as the state agency most likely to have on-going influence regarding CCA costs and benefits, represent what has been termed "regulatory risk". Regulatory risk can be defined as the risk of change in CCA program costs and benefits due to external decision-making by regulators (whether Federal or State) which impact the CCA program. The SFPUC and SFE (the Departments), both represented by the City Attorney's office, have and are participating in these CPUC proceedings to advance the goals of CCA. In general the Departments have and are advancing arguments intended to: - reasonably assess the costs of CCA start-up and on-going implementation, preserve the legal rights of the CCA to determine its own goals regarding e.g. a CCA supply portfolio or rate-setting options (within the limits imposed by State legislation), maintain or enhance options for CCA supply or energy efficiency services, and wherever possible obtain regulatory certainty so as to reduce the level of overall regulatory risk.
The chapter is organized by the various key CPUC proceedings currently underway. The listing of proceedings is not exhaustive, indeed the Departments are monitoring other CPUC and CEC proceedings that could influence overall CCA decision-making. The Key Proceedings Are:

- The Community Choice Aggregation (CCA) Proceeding
- Cost Responsibility Surcharge (CRS) True-Up Proceedings.
- The Resource Adequacy Requirements Proceeding (RAR)
- The Renewable Portfolio Standards (RPS) Proceedings
- The PG&E General Rate Case (GRC Phase 2 Proceeding
- The Energy Efficiency Administration Proceeding

2. CCA PROCEEDINGS

2.1 <u>The CPUC Phase 1 CCA Proceeding Decision (D. 04-12-046)</u>

On December 16, 2004 the CPUC issued D.04-12-046 in the CCA Proceeding (Rulemaking 03-10-003). This decision resolved Phase 1 issues in the CCA proceeding. The key points of this phase 1 decision are:

- **Setting a Cost Responsibility Surcharge (CRS) of 2.0 cents/kWh for at least the next 18 Months.** [1] The CRS is a new charge that will appear on CCA customers' bills. The charge is set to ensure that the remaining bundled customers of the investor owned utilities (IOU's) remain economically indifferent to the departure of the CCA customers.

[1] This effectively becomes a 1.8-cents/kWh surcharge since the preexisting 0.2 cent/kWh CTC charge will be dropped from CCA customer bills.

- **Allowing CCAs to Determine Which Customers to Serve.** The Commission left the marketing of the CCA program to the CCA and did not specify which customers the CCA should serve. However the Commission requires that a CCA, pursuant to AB 117, must offer service to all residential customers within the CCA.
- **Determining that Electric Load and Customer Information Should Be Readily Available to Potential CCAs.** The Commission found that the IOU's cannot withhold electric customer or load information from cities pursuing CCA but requires that potential CCAs sign non-disclosure forms to obtain confidential data.
- **Allowing CCAs to Phase-In CCA Implementation.** The Commission allows CCAs to implement the CCA program over a reasonable amount of time. However utilities are allowed to recover any additional costs of such a Phase-In directly from the CCA.
- **CCAs Must Use the IOU System Average Load Profile (SAP) for Scheduling and Settlement of Power Transactions at the CA Independent System Operator (CAISO).** The Commission determined that CCAs, irrespective of deviations from the SAP, must use the SAP for these vital transactions.
- **IOU Implementation Costs to Set-Up System Changes for CCA Should Be Recovered From All Ratepayers.** The Commission determined that general costs to set-up the system changes, e.g. in software or other processes, to accommodate CCA should be recovered from all ratepayers and not directly from CCAs.

The SFPUC, represented by the City Attorney's office, advocated a number of winning positions in this proceeding: - including the adoption of a CRS charge in Phase 1, adoption of readily available access to required electric load and customer information, allowance of the Phase-In option to CCA, and recovery of Implementation Costs from all Ratepayers. Unfortunately the SFPUC was unsuccessful in arguing that cities be allowed to explore the option of using a city specific load profile. While the Commission's adoption of an SAP requirement may not, on average, result in additional supply costs to the CCA it will expose the CCA to much higher cost purchasing costs during hot weather periods, it will also complicate efforts to meet the Commission's ultimate RAR, as well as the CCA energy efficiency and demand response programs. Also it is unfortunate that the Commission adopted a CRS charge significantly higher than advocated by the SFPUC.

2.2 CCA Phase 2 Proceeding.

The CPUC Ruling setting forth the issues and timetable for Phase 2 of the CCA proceeding was issued on February 3/05. During March the Commission intends to address a number of implementation and operational details of CCA, updates to the CRS charge, and protocols for CCA implementation plan filings at the Commission. The Commission set forth a workshop approach to consider these detailed issues with the objective of resolving or narrowing disputes that will be the subject of testimony and hearings in April and May. The Commission did not set forth any final decision-making

timetable but the Departments believe the Commission should resolve these issues by the end of 2005.
The workshop schedule is as follows:

- Workshop 1 – CRS Vintaging March 3. This workshop will first examine the complexities of vintaging each CCAs CRS liabilities so that the Commission can properly forecast and true-up individual CCA CRS responsibility. Potential CCAs have argued that vintaging is required under AB117 so that a CCA is not responsible for any increase in CRS charges due to IOU procurement decisions subsequent to a particular CCA implementation. However the CPUC is concerned about regulatory complexity and the need to review on an annual basis many CRS charges, as well as a need to shift the responsibility for CRS calculations away from the DWR and to the IOUs. The SFPUC will likely propose that vintaging is required under the law, and therefore CCAs should not be responsible for IOU contracting subsequent to CCA implementation. However the SFPUC looks forward to exploring administratively simplified ways to equitably assess CRS and allow for prompt true-ups in CRS proceedings. In this workshop the Commission also requires the IOU's to update the CRS forecasts – presumably for the year 2007 onward. If the IOU's produce such forecasts the SFPUC anticipates arguing that the CRS for the year 2007 should be considerably lower than the adopted 2005/2006 CRS charge of 2.0 cents/kWh.
- Workshop 2 – Open Season Procedures and Policies. In the Phase 1 Decision the Commission endorsed the concept of an IOU "Open Season" – a set period of time each year when CCA implementation should occur. The intent of the Open –Season is to allow parties to focus implementation efforts during one period so as to reduce errors and complexities in short-term power contracting and avoid overall over or under contracting for power. The SFPUC believes the "Open Season" concept has merit. However the SFPUC anticipates raising concerns about the risks in CCA load forecasting due to customer opt-out abilities, and the difficulty of integrating the Open-Season concept with a Phase-in approach to CCA.
- Workshop 3 – Tariffs. This workshop will examine the February 14, 2005 CCA tariff filings of the IOU's in depth. These proposed tariffs are foundational to the charges to CCAs by the IOU's and the rules the IOU's propose that CCAs follow in interacting with IOU's to serve customers. Among the detailed charges the utilities will propose in the tariffs the Departments anticipate focusing on the reasonableness of PG&E's proposed CCA billing charges, PG&E's switching rule proposals, any PG&E proposed Phase-In costs, PG&E's opt-out notification costs, and PG&E's proposed treatment of partial or unpaid customer bills.
- Workshop 4 – CCA Implementation Plans. This workshop is intended to set the procedures and nature of the Commissions review of CCA implementation plan filings. The SFPUC anticipates arguing for swift CPUC resolution of CCA implementation plans filed according to Commission requirements. The SFPUC also anticipates raising the issue of coordination of CPUC approval of Implementation Plans with the timing required for a CCA to make Resource Adequacy Requirement (RAR) filings – due by September 30, each year.

- Workshop 5 – Credits and Liability for In-Kind Power. This workshop, required by D.04-12-045, will explore whether and how a CCA could take delivery or somehow obtain credit for DWR or utility power that is the source of the CRS liability of the CCA. The SFPUC anticipates significant controversy about the policy and legal issues surrounding this topic.

Overall the Departments look forward to the Workshop approach set by the CPUC and hope it will work to equitably resolve a number of issues and thereby accelerate the CPUC decision-making for Phase 2 of the proceeding.

3. CRS UPDATE PROCEEDINGS

D.04-12-046 requires that utilities enter CCA CRS costs and revenues into balancing accounts for annual reconciliation in proceedings addressing the CRS for direct access customers. The SFPUC supports this proposal. However there is a considerable regulatory risk attached to CRS true up.

3.1 The Risk Attached to CRS True Up.

The Commission is likely to set the CCA CRS on a conservative basis. That is the Commissions tendency will be to over forecast the value of the CRS to assure themselves that bundled ratepayers remain indifferent to CCA implementation. This will likely result in CCA customers overpaying the CRS on a forecast basis and looking to the CRS True-Up as the means of redressing the balance. For example a 1.8 cent/kWh CRS charge in year 1 for CCSF customers equates to about $77 million on an annual basis. If this charge were, e.g., 0.5 cents/kWh too high in one annual period the result is a CCA customer overpayment of about $21 million. It is obvious that such an overcharge should be reduced as soon as possible i.e. by timely CPUC decision of a new CRS charge for year 2 incorporating a true-up of year 1's overcharge as a reduction in the CRS rates for CCA customers. At this juncture regulatory risk regarding the timeliness of Commission decision-making is a vital factor. If both the setting of a new annual CRS charge and the true up of the previous years CRS charge are delayed by the Commission then considerable overpayment can occur for CCA customers. Inclusion of interest payments on the overcharges while helpful does not diminish the real-time decision-making of CCA customers regarding any alternatives to what they might well view as high CCA rates and bills.

The SFPUC anticipates the CPUC will assure potential CCAs regarding prompt regulatory timing. However the Commissions recent history regarding the timeliness of CRS calculations for direct access customers is not a good precedent. For example the Commission issued D.05-01-040 on January 27, 2005. This proceeding was established in January of 2002 to set the CRS rates for direct access customers and has only now determined the true-up calculations for direct access customers for 2001-2002.

In the economic analysis conducted by Altos in Chapter 4, the SFPUC provided Altos what we believe to be a realistic forecast of the likely CRS charges to be set by the Commission between now and 2012.[2] Given the large degrees of uncertainty regarding timing of true-up proceedings, and the outcome of true-up proceedings the Altos economic analysis of Chapter 4 does not include any potential impacts of CRS true-ups. This ex post true up of actual CRS costs provides another degree of uncertainty in CCA product design. The risk, particularly around the scale and timing of CRS true-ups means that "guarantees" to CCA customers of any length of rate stability become problematic.

4. THE RESOURCE ADEQUACY REQUIREMENTS (RAR) PROCEEDING

As part of the Rulemaking regarding Electric Utility Resource Planning (R.04-04-003) the CPUC has set an overall policy that all Load Serving Entities (LSEs) shall meet resource adequacy requirements. RAR is necessarily set by the CPUC due to the varying interests and potentially conflicting interpretations of RAR by different LSEs. Because CCAs are of course LSEs the working assumption of the SFPUC is that the CPUC's RAR policy will also apply to CCAs. However the interaction of whatever final RAR rules set by the CPUC with the response of market participants might lead to iterations of RAR rules. This will create a continued uncertainty for ultimate CCA resource portfolio costs.

4.1 Overall RAR.

In D. 04-10-035 the Commission ordered all LSEs (except municipal utilities) to meet a Planning Reserve Margin (PRM) of 15-17% to be met by June 1, 2006, to submit by September of each year a load forecast and compliance filings which demonstrate 90% forward commitments for the May-September period of the following year, and to obtain a mix of resources capable of meeting 90% of their monthly contribution to monthly system peak. In addition a year round 100% month ahead obligation to obtain sufficient capacity to serve loads was established. However details regarding the timing and form of compliance filings, sanctions, and locational procurement resource adequacy were left, in the first instance to Phase 2 workshops. Recently the CPUC issued a ruling (February 8, 2005) seeking to clarify the forward commitment obligation of D.04-10-035.
In terms of the CCSF Draft Implementation Plan the contracting model used by Altos in Chapter 4 has assumed that the CCA forward contracts for 100% of its capacity on a one month ahead basis, as well as forward contracting at least 6 months ahead to meet a peak reserve margin of 117%. The impact of this mandated contracting approach results in the CCA having a net long position in every month and a need to sell power into the spot market.

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[2] These assumed CRS charges are those of Scenario 4 presented by DWR in the CCA Phase 1 Proceeding, and are as follows: 2007 – 1.8 cents/kWh, 2008 – 1.2 cents/kWh, 2009 – 1.0 cents/kWh, 2010 – 0.7 cents/kWh, 2011 – 0.5 cents/kWh, 2012 – 0.2 cents/kWh.

Since both PG&E and a city CCA will have to meet these overall RAR the SFPUC is currently monitoring the RAR proceeding to ensure that the latest CPUC findings are incorporated into the Draft Implementation Plan. The SFPUC has, however, have already expressed two concerns: -

- First that the timing of CPUC approvals of CCA Implementation Plans be aligned with required CCA filings on RAR due by September 30th of each year for the following summer period.
- Second that there exists a significant CPUC inconsistency in mandating accuracy in CCA load forecasting and resource contracting to meet RAR (with the threat of sanctions for inaccuracy) and then requiring CCAs to use inaccurate SAPs for scheduling and settlement of CCA loads with the ISO – and presumably with the CPUC for RAR.

4.2 Local Resource Adequacy Requirements (LRA).

In Phase 2 RAR workshops particular attention is focused upon the deliverability of electric resources within what are termed load pockets. Load pockets are particular areas of the electric grid that are transmission constrained and therefore require that generation be sited within the pocket to ensure resource adequacy. CCSF is an example of such a load pocket. There are a number of issues related to LSEs demonstrating deliverability of resources within load pockets. First determining individual LSE load obligations within a load pocket can result in significant calculation complexity e.g. within CCSF there are potentially four entities having to serve loads. Second allocation of recovery of LRA costs from customers could potentially favor LSEs – like PG&E – that could spread such costs over all customers. Third market power issues also loom large in meeting LRA since one or few generation sources may be pivotal in meeting LRA.

To date Altos has not added an LRA component to the contract mix for meeting potential CCA loads. The crucial issue – which the SFPUC has and will continue to raise – is the need for consistency in cost allocation such that PG&E is not granted a competitive advantage over the CCA by spreading any of its CCSF related LRA costs over all its bundled customers.

5. THE RENEWABLE PORTFOLIO STANDARDS (RPS) PROCEEDING.

The CPUC RPS proceeding (R.04-04-026) is the vehicle for implementation of Senate Bill 1078 (passed in September 2002) which established that IOUs must demonstrate by 2017 that 20% of their electric generation output comes from sources defined as renewable. At the CCSF level, the CCA Ordinance (86-04) requires the City's CCA Draft Implementation Plan to address how CCSF could meet or beat the RPS standard required of PG&E by law (Ordinance 86-04, Section 3 (A)(3)). The CCA Ordinance contemplates the City using voter-approved Proposition H Revenue Bonds to finance and build renewable generation to supply CCA load. While this has been the City's policy

direction for renewable procurement for CCA, the CPUC may determine in the RPS proceeding that CCAs are to comply with the State RPS standard in the exact same manner as the IOUs.

To date, the SFPUC has taken the position in this proceeding that it would be inappropriate for the Commission to apply the exact same RPS compliance rules, processes, procedures, and timelines developed for the IOUs to CCAs. The IOUs' include the eligible renewable generation facilities they own toward their baseline renewable portfolio percentage. The Commission establishes annual procurement targets (APTs) for each utility that is at least a 1% increase on their current renewable energy content (baseline). Currently, the IOUs are required to enter into long-term contracts (10-20 years in duration) with renewable generation facilities via a CPUC-approved RPS solicitation process to meet their incremental procurement targets (IPT).[3] IOUs are required to consult with their Procurement Review Groups (PGRs) to determine the ranking of bids submitted during the RPS solicitation. The PRGs ensure that the IOUs have used a "least-cost/best-fit" approach to ranking bids submitted by RPS eligible renewable generators. An important principle embedded in the RPS statute is that the IOUs are not required to pay any "above market" costs associated with RPS compliant power purchase agreements. To accommodate the likelihood that renewable power would exceed the average market price of baseload and peaking power products (including non-renewable generation), the Legislature established a pool of funds to cover the above market portion of the cost of winning RPS bids. The CEC administers the disbursement of these funds, which are called Supplemental Energy Payments (SEPs). Once the CPUC's Energy Division determines the Market Price Referents (MPRs) for each renewable power solicitation, renewable power merchants can receive SEP to cover the above market portion of their winning RPS bids. The CPUC recently issued a ruling disclosing the MPRs to be used in evaluating bids received from the 2004 renewable power solicitations conducted by the utilities. The MPR for 10-year baseload power contracts is 5.61 cents per kilowatt-hour and 10.79 cents per kWh for peaking power contracts of 10 years in duration. Presumably, the MPRs represent the ceiling for which the IOUs are required to pay for RPS-related power contracts. Above market costs associated with winning RPS bids will be eligible for SEP.

The CPUC administered IOU RPS procurement process is complicated and likely to be administratively burdensome for CCAs if imposed as is. Moreover, the IOU RPS compliance method and guidelines may hamper the City's ability to finance and build its own generation for CCAs by locking the City into a singular method of signing 10-plus year contracts for up to 20% of its energy portfolio. Strict application of these rules and procedures will greatly diminish the City's resource planning autonomy. The SFPUC has argued that if the Commission determines that CCAs are required to comply with the

[3] The Incremental Procurement Target is defined by CPUC D.04-06-014 as "at least 1% of the previous year's total retail electrical sales, including power sold to a utility's customers from its DWR contracts. The Commission retains the authority to increase this amount above 1% to meet state goals for renewable generation." Annual procurement target is defined as "the amount of renewable generation a utility must procure in order to meet the statutory requirement that it increase its renewable procurement by at least 1 percent of retail sales per year." The APT = prior year renewable baseline amount + IPT.

general procurement requirements of SB 1078, that additional programmatic flexibilities should be incorporated into the program such as use of Renewable Energy Credits (RECs)[4]. The SFPUC has also argued that if CCAs are required to meet a State-mandated RPS target, then the SEP available to the IOUs to pay for above market costs of renewable energy should also be available to CCAs. A Commission decision on the issue of CCA participation in the State RPS program is expected prior to May of 2005.

5.1 Do the Legal Requirements of Senate Bill 1078 Apply to CCAs?

In recent filings before the CPUC the CCSF argued, and will continue to argue, that not all the specific provisions of Senate Bill 1078 apply to CCAs. Most importantly the CCSF does not agree that a CCA is required under State law to meet the 20% RPS standard by the year 2017, or the accelerated CPUC policy goal of 20% RPS by 2010, with penalties as high $0.05/kilowatt-hour if it fails. The CCSF recognizes that all retail sellers of electricity should contribute to meeting State's goals. CCAs are public entities capable of establishing their own renewable standards and accountable to their constituents that will hold a CCA to meeting its goals regarding the timing and nature of an RPS.

5.2 CCAs Should Not Have to Obtain CPUC Approval for Renewable Power Contracts.

The CPUC has established RPS compliance rules for IOUs that require pre-approval for contracts as well as extensive reporting and compliance requirements (for example, a competitive solicitation process approved by the CPUC and reviewed by the PRGs). Some parties argue that CCAs should have to follow an identical contracting approach for Renewable Power. The CCSF argued and will continue to argue that CCAs should not be required to meet the administratively complex and intrusive approach required of IOUs. CCAs should be able to conduct their own competitive solicitations for renewable energy contracts and do not need CPUC supervision of this process.

6. PACIFIC GAS AND ELECTRIC COMPANY'S (PG&E) GENERAL RATE CASE PHASE 2.

This proceeding (A.04-06-024) is the first substantial review of PG&E's marginal costs, revenue allocation, and rate design in nearly a decade. PG&E's rate proposals, set to become effective in January of 2006, if adopted by the CPUC, would shift a significant amount of generation costs to residential and small business customers and would significantly decrease the generation rates paid by larger commercial and industrial

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Community Choice Aggregation
Draft Implementation Plan

Chapter 9
CCSF Participation in CPUC Proceedings Related to Community Choice Aggregation.

Prepared
By the SF PUC

March 22, 2005

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1. OBJECTIVE

This chapter reviews current CPUC proceedings that most directly influence the CCA decision-making for the city. These CPUC proceedings, and the CPUC itself as the state agency most likely to have on-going influence regarding CCA costs and benefits, represent what has been termed "regulatory risk". Regulatory risk can be defined as the risk of change in CCA program costs and benefits due to external decision-making by regulators (whether Federal or State) which impact the CCA program. The SFPUC and SFE (the Departments), both represented by the City Attorney's office, have and are participating in these CPUC proceedings to advance the goals of CCA. In general the Departments have and are advancing arguments intended to: - reasonably assess the costs of CCA start-up and on-going implementation, preserve the legal rights of the CCA to determine its own goals regarding e.g. a CCA supply portfolio or rate-setting options (within the limits imposed by State legislation), maintain or enhance options for CCA supply or energy efficiency services, and wherever possible obtain regulatory certainty so as to reduce the level of overall regulatory risk.

The chapter is organized by the various key CPUC proceedings currently underway. The listing of proceedings is not exhaustive, indeed the Departments are monitoring other CPUC and CEC proceedings that could influence overall CCA decision-making. The Key Proceedings Are:

- The Community Choice Aggregation (CCA) Proceeding
- Cost Responsibility Surcharge (CRS) True-Up Proceedings.
- The Resource Adequacy Requirements Proceeding (RAR)
- The Renewable Portfolio Standards (RPS) Proceedings
- The PG&E General Rate Case (GRC Phase 2 Proceeding
- The Energy Efficiency Administration Proceeding

2. CCA PROCEEDINGS

2.1 <u>The CPUC Phase 1 CCA Proceeding Decision (D. 04-12-046)</u>

On December 16, 2004 the CPUC issued D.04-12-046 in the CCA Proceeding (Rulemaking 03-10-003). This decision resolved Phase 1 issues in the CCA proceeding. The key points of this phase 1 decision are:

- **Setting a Cost Responsibility Surcharge (CRS) of 2.0 cents/kWh for at least the next 18 Months.** [1] The CRS is a new charge that will appear on CCA customers' bills. The charge is set to ensure that the remaining bundled customers of the investor owned utilities (IOU's) remain economically indifferent to the departure of the CCA customers.

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[1] This effectively becomes a 1.8-cents/kWh surcharge since the preexisting 0.2 cent/kWh CTC charge will be dropped from CCA customer bills.

- **Allowing CCAs to Determine Which Customers to Serve.** The Commission left the marketing of the CCA program to the CCA and did not specify which customers the CCA should serve. However the Commission requires that a CCA, pursuant to AB 117, must offer service to all residential customers within the CCA.
- **Determining that Electric Load and Customer Information Should Be Readily Available to Potential CCAs.** The Commission found that the IOU's cannot withhold electric customer or load information from cities pursuing CCA but requires that potential CCAs sign non-disclosure forms to obtain confidential data.
- **Allowing CCAs to Phase-In CCA Implementation.** The Commission allows CCAs to implement the CCA program over a reasonable amount of time. However utilities are allowed to recover any additional costs of such a Phase-In directly from the CCA.
- **CCAs Must Use the IOU System Average Load Profile (SAP) for Scheduling and Settlement of Power Transactions at the CA Independent System Operator (CAISO).** The Commission determined that CCAs, irrespective of deviations from the SAP, must use the SAP for these vital transactions.
- **IOU Implementation Costs to Set-Up System Changes for CCA Should Be Recovered From All Ratepayers.** The Commission determined that general costs to set-up the system changes, e.g. in software or other processes, to accommodate CCA should be recovered from all ratepayers and not directly from CCAs.

The SFPUC, represented by the City Attorney's office, advocated a number of winning positions in this proceeding: - including the adoption of a CRS charge in Phase 1, adoption of readily available access to required electric load and customer information, allowance of the Phase-In option to CCA, and recovery of Implementation Costs from all Ratepayers. Unfortunately the SFPUC was unsuccessful in arguing that cities be allowed to explore the option of using a city specific load profile. While the Commission's adoption of an SAP requirement may not, on average, result in additional supply costs to the CCA it will expose the CCA to much higher cost purchasing costs during hot weather periods, it will also complicate efforts to meet the Commission's ultimate RAR, as well as the CCA energy efficiency and demand response programs. Also it is unfortunate that the Commission adopted a CRS charge significantly higher than advocated by the SFPUC.

2.2 <u>CCA Phase 2 Proceeding.</u>

The CPUC Ruling setting forth the issues and timetable for Phase 2 of the CCA proceeding was issued on February 3/05. During March the Commission intends to address a number of implementation and operational details of CCA, updates to the CRS charge, and protocols for CCA implementation plan filings at the Commission. The Commission set forth a workshop approach to consider these detailed issues with the objective of resolving or narrowing disputes that will be the subject of testimony and hearings in April and May. The Commission did not set forth any final decision-making

timetable but the Departments believe the Commission should resolve these issues by the end of 2005.
The workshop schedule is as follows:

- Workshop 1 – CRS Vintaging March 3. This workshop will first examine the complexities of vintaging each CCAs CRS liabilities so that the Commission can properly forecast and true-up individual CCA CRS responsibility. Potential CCAs have argued that vintaging is required under AB117 so that a CCA is not responsible for any increase in CRS charges due to IOU procurement decisions subsequent to a particular CCA implementation. However the CPUC is concerned about regulatory complexity and the need to review on an annual basis many CRS charges, as well as a need to shift the responsibility for CRS calculations away from the DWR and to the IOUs. The SFPUC will likely propose that vintaging is required under the law, and therefore CCAs should not be responsible for IOU contracting subsequent to CCA implementation. However the SFPUC looks forward to exploring administratively simplified ways to equitably assess CRS and allow for prompt true-ups in CRS proceedings. In this workshop the Commission also requires the IOU's to update the CRS forecasts – presumably for the year 2007 onward. If the IOU's produce such forecasts the SFPUC anticipates arguing that the CRS for the year 2007 should be considerably lower than the adopted 2005/2006 CRS charge of 2.0 cents/kWh.
- Workshop 2 – Open Season Procedures and Policies. In the Phase 1 Decision the Commission endorsed the concept of an IOU "Open Season" – a set period of time each year when CCA implementation should occur. The intent of the Open –Season is to allow parties to focus implementation efforts during one period so as to reduce errors and complexities in short-term power contracting and avoid overall over or under contracting for power. The SFPUC believes the "Open Season" concept has merit. However the SFPUC anticipates raising concerns about the risks in CCA load forecasting due to customer opt-out abilities, and the difficulty of integrating the Open-Season concept with a Phase-in approach to CCA.
- Workshop 3 – Tariffs. This workshop will examine the February 14, 2005 CCA tariff filings of the IOU's in depth. These proposed tariffs are foundational to the charges to CCAs by the IOU's and the rules the IOU's propose that CCAs follow in interacting with IOU's to serve customers. Among the detailed charges the utilities will propose in the tariffs the Departments anticipate focusing on the reasonableness of PG&E's proposed CCA billing charges, PG&E's switching rule proposals, any PG&E proposed Phase-In costs, PG&E's opt-out notification costs, and PG&E's proposed treatment of partial or unpaid customer bills.
- Workshop 4 – CCA Implementation Plans. This workshop is intended to set the procedures and nature of the Commissions review of CCA implementation plan filings. The SFPUC anticipates arguing for swift CPUC resolution of CCA implementation plans filed according to Commission requirements. The SFPUC also anticipates raising the issue of coordination of CPUC approval of Implementation Plans with the timing required for a CCA to make Resource Adequacy Requirement (RAR) filings – due by September 30, each year.

- Workshop 5 – Credits and Liability for In-Kind Power. This workshop, required by D.04-12-045, will explore whether and how a CCA could take delivery or somehow obtain credit for DWR or utility power that is the source of the CRS liability of the CCA. The SFPUC anticipates significant controversy about the policy and legal issues surrounding this topic.

Overall the Departments look forward to the Workshop approach set by the CPUC and hope it will work to equitably resolve a number of issues and thereby accelerate the CPUC decision-making for Phase 2 of the proceeding.

3. CRS UPDATE PROCEEDINGS

D.04-12-046 requires that utilities enter CCA CRS costs and revenues into balancing accounts for annual reconciliation in proceedings addressing the CRS for direct access customers. The SFPUC supports this proposal. However there is a considerable regulatory risk attached to CRS true up.

3.1 The Risk Attached to CRS True Up.

The Commission is likely to set the CCA CRS on a conservative basis. That is the Commissions tendency will be to over forecast the value of the CRS to assure themselves that bundled ratepayers remain indifferent to CCA implementation. This will likely result in CCA customers overpaying the CRS on a forecast basis and looking to the CRS True-Up as the means of redressing the balance. For example a 1.8 cent/kWh CRS charge in year 1 for CCSF customers equates to about $77 million on an annual basis. If this charge were, e.g., 0.5 cents/kWh too high in one annual period the result is a CCA customer overpayment of about $21 million. It is obvious that such an overcharge should be reduced as soon as possible i.e. by timely CPUC decision of a new CRS charge for year 2 incorporating a true-up of year 1's overcharge as a reduction in the CRS rates for CCA customers. At this juncture regulatory risk regarding the timeliness of Commission decision-making is a vital factor. If both the setting of a new annual CRS charge and the true up of the previous years CRS charge are delayed by the Commission then considerable overpayment can occur for CCA customers. Inclusion of interest payments on the overcharges while helpful does not diminish the real-time decision-making of CCA customers regarding any alternatives to what they might well view as high CCA rates and bills.

The SFPUC anticipates the CPUC will assure potential CCAs regarding prompt regulatory timing. However the Commissions recent history regarding the timeliness of CRS calculations for direct access customers is not a good precedent. For example the Commission issued D.05-01-040 on January 27, 2005. This proceeding was established in January of 2002 to set the CRS rates for direct access customers and has only now determined the true-up calculations for direct access customers for 2001-2002.

In the economic analysis conducted by Altos in Chapter 4, the SFPUC provided Altos what we believe to be a realistic forecast of the likely CRS charges to be set by the Commission between now and 2012.[2] Given the large degrees of uncertainty regarding timing of true-up proceedings, and the outcome of true-up proceedings the Altos economic analysis of Chapter 4 does not include any potential impacts of CRS true-ups. This ex post true up of actual CRS costs provides another degree of uncertainty in CCA product design. The risk, particularly around the scale and timing of CRS true-ups means that "guarantees" to CCA customers of any length of rate stability become problematic.

4. THE RESOURCE ADEQUACY REQUIREMENTS (RAR) PROCEEDING

As part of the Rulemaking regarding Electric Utility Resource Planning (R.04-04-003) the CPUC has set an overall policy that all Load Serving Entities (LSEs) shall meet resource adequacy requirements. RAR is necessarily set by the CPUC due to the varying interests and potentially conflicting interpretations of RAR by different LSEs. Because CCAs are of course LSEs the working assumption of the SFPUC is that the CPUC's RAR policy will also apply to CCAs. However the interaction of whatever final RAR rules set by the CPUC with the response of market participants might lead to iterations of RAR rules. This will create a continued uncertainty for ultimate CCA resource portfolio costs.

4.1 Overall RAR.

In D. 04-10-035 the Commission ordered all LSEs (except municipal utilities) to meet a Planning Reserve Margin (PRM) of 15-17% to be met by June 1, 2006, to submit by September of each year a load forecast and compliance filings which demonstrate 90% forward commitments for the May-September period of the following year, and to obtain a mix of resources capable of meeting 90% of their monthly contribution to monthly system peak. In addition a year round 100% month ahead obligation to obtain sufficient capacity to serve loads was established. However details regarding the timing and form of compliance filings, sanctions, and locational procurement resource adequacy were left, in the first instance to Phase 2 workshops. Recently the CPUC issued a ruling (February 8, 2005) seeking to clarify the forward commitment obligation of D.04-10-035.
In terms of the CCSF Draft Implementation Plan the contracting model used by Altos in Chapter 4 has assumed that the CCA forward contracts for 100% of its capacity on a one month ahead basis, as well as forward contracting at least 6 months ahead to meet a peak reserve margin of 117%. The impact of this mandated contracting approach results in the CCA having a net long position in every month and a need to sell power into the spot market.

[2] These assumed CRS charges are those of Scenario 4 presented by DWR in the CCA Phase 1 Proceeding, and are as follows: 2007 – 1.8 cents/kWh, 2008 – 1.2 cents/kWh, 2009 – 1.0 cents/kWh, 2010 – 0.7 cents/kWh, 2011 – 0.5 cents/kWh, 2012 – 0.2 cents/kWh.

Since both PG&E and a city CCA will have to meet these overall RAR the SFPUC is currently monitoring the RAR proceeding to ensure that the latest CPUC findings are incorporated into the Draft Implementation Plan. The SFPUC has, however, have already expressed two concerns: -

- First that the timing of CPUC approvals of CCA Implementation Plans be aligned with required CCA filings on RAR due by September 30th of each year for the following summer period.
- Second that there exists a significant CPUC inconsistency in mandating accuracy in CCA load forecasting and resource contracting to meet RAR (with the threat of sanctions for inaccuracy) and then requiring CCAs to use inaccurate SAPs for scheduling and settlement of CCA loads with the ISO – and presumably with the CPUC for RAR.

4.2 Local Resource Adequacy Requirements (LRA).

In Phase 2 RAR workshops particular attention is focused upon the deliverability of electric resources within what are termed load pockets. Load pockets are particular areas of the electric grid that are transmission constrained and therefore require that generation be sited within the pocket to ensure resource adequacy. CCSF is an example of such a load pocket. There are a number of issues related to LSEs demonstrating deliverability of resources within load pockets. First determining individual LSE load obligations within a load pocket can result in significant calculation complexity e.g. within CCSF there are potentially four entities having to serve loads. Second allocation of recovery of LRA costs from customers could potentially favor LSEs – like PG&E – that could spread such costs over all customers. Third market power issues also loom large in meeting LRA since one or few generation sources may be pivotal in meeting LRA.

To date Altos has not added an LRA component to the contract mix for meeting potential CCA loads. The crucial issue – which the SFPUC has and will continue to raise – is the need for consistency in cost allocation such that PG&E is not granted a competitive advantage over the CCA by spreading any of its CCSF related LRA costs over all its bundled customers.

5. THE RENEWABLE PORTFOLIO STANDARDS (RPS) PROCEEDING.

The CPUC RPS proceeding (R.04-04-026) is the vehicle for implementation of Senate Bill 1078 (passed in September 2002) which established that IOUs must demonstrate by 2017 that 20% of their electric generation output comes from sources defined as renewable. At the CCSF level, the CCA Ordinance (86-04) requires the City's CCA Draft Implementation Plan to address how CCSF could meet or beat the RPS standard required of PG&E by law (Ordinance 86-04, Section 3 (A)(3)). The CCA Ordinance contemplates the City using voter-approved Proposition H Revenue Bonds to finance and build renewable generation to supply CCA load. While this has been the City's policy

direction for renewable procurement for CCA, the CPUC may determine in the RPS proceeding that CCAs are to comply with the State RPS standard in the exact same manner as the IOUs.

To date, the SFPUC has taken the position in this proceeding that it would be inappropriate for the Commission to apply the exact same RPS compliance rules, processes, procedures, and timelines developed for the IOUs to CCAs. The IOUs' include the eligible renewable generation facilities they own toward their baseline renewable portfolio percentage. The Commission establishes annual procurement targets (APTs) for each utility that is at least a 1% increase on their current renewable energy content (baseline). Currently, the IOUs are required to enter into long-term contracts (10-20 years in duration) with renewable generation facilities via a CPUC-approved RPS solicitation process to meet their incremental procurement targets (IPT).[3] IOUs are required to consult with their Procurement Review Groups (PGRs) to determine the ranking of bids submitted during the RPS solicitation. The PRGs ensure that the IOUs have used a "least-cost/best-fit" approach to ranking bids submitted by RPS eligible renewable generators. An important principle embedded in the RPS statute is that the IOUs are not required to pay any "above market" costs associated with RPS compliant power purchase agreements. To accommodate the likelihood that renewable power would exceed the average market price of baseload and peaking power products (including non-renewable generation), the Legislature established a pool of funds to cover the above market portion of the cost of winning RPS bids. The CEC administers the disbursement of these funds, which are called Supplemental Energy Payments (SEPs). Once the CPUC's Energy Division determines the Market Price Referents (MPRs) for each renewable power solicitation, renewable power merchants can receive SEP to cover the above market portion of their winning RPS bids. The CPUC recently issued a ruling disclosing the MPRs to be used in evaluating bids received from the 2004 renewable power solicitations conducted by the utilities. The MPR for 10-year baseload power contracts is 5.61 cents per kilowatt-hour and 10.79 cents per kWh for peaking power contracts of 10 years in duration. Presumably, the MPRs represent the ceiling for which the IOUs are required to pay for RPS-related power contracts. Above market costs associated with winning RPS bids will be eligible for SEP.

The CPUC administered IOU RPS procurement process is complicated and likely to be administratively burdensome for CCAs if imposed as is. Moreover, the IOU RPS compliance method and guidelines may hamper the City's ability to finance and build its own generation for CCAs by locking the City into a singular method of signing 10-plus year contracts for up to 20% of its energy portfolio. Strict application of these rules and procedures will greatly diminish the City's resource planning autonomy. The SFPUC has argued that if the Commission determines that CCAs are required to comply with the

[3] The Incremental Procurement Target is defined by CPUC D.04-06-014 as "at least 1% of the previous year's total retail electrical sales, including power sold to a utility's customers from its DWR contracts. The Commission retains the authority to increase this amount above 1% to meet state goals for renewable generation." Annual procurement target is defined as "the amount of renewable generation a utility must procure in order to meet the statutory requirement that it increase its renewable procurement by at least 1 percent of retail sales per year." The APT = prior year renewable baseline amount + IPT.

general procurement requirements of SB 1078, that additional programmatic flexibilities should be incorporated into the program such as use of Renewable Energy Credits (RECs)[4]. The SFPUC has also argued that if CCAs are required to meet a State-mandated RPS target, then the SEP available to the IOUs to pay for above market costs of renewable energy should also be available to CCAs. A Commission decision on the issue of CCA participation in the State RPS program is expected prior to May of 2005.

5.1 Do the Legal Requirements of Senate Bill 1078 Apply to CCAs?

In recent filings before the CPUC the CCSF argued, and will continue to argue, that not all the specific provisions of Senate Bill 1078 apply to CCAs. Most importantly the CCSF does not agree that a CCA is required under State law to meet the 20% RPS standard by the year 2017, or the accelerated CPUC policy goal of 20% RPS by 2010, with penalties as high $0.05/kilowatt-hour if it fails. The CCSF recognizes that all retail sellers of electricity should contribute to meeting State's goals. CCAs are public entities capable of establishing their own renewable standards and accountable to their constituents that will hold a CCA to meeting its goals regarding the timing and nature of an RPS.

5.2 CCAs Should Not Have to Obtain CPUC Approval for Renewable Power Contracts.

The CPUC has established RPS compliance rules for IOUs that require pre-approval for contracts as well as extensive reporting and compliance requirements (for example, a competitive solicitation process approved by the CPUC and reviewed by the PRGs). Some parties argue that CCAs should have to follow an identical contracting approach for Renewable Power. The CCSF argued and will continue to argue that CCAs should not be required to meet the administratively complex and intrusive approach required of IOUs. CCAs should be able to conduct their own competitive solicitations for renewable energy contracts and do not need CPUC supervision of this process.

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Community Choice Aggregation
Draft Implementation Plan

Appendix A:
A Functional Analysis and Cost Estimates of "Public Face" CCA Operations Conducted by CCSF Employees.

Prepared for
The City and County of San Francisco

By
The Structure Group
Tiburon, CA.

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1. INTRODUCTION

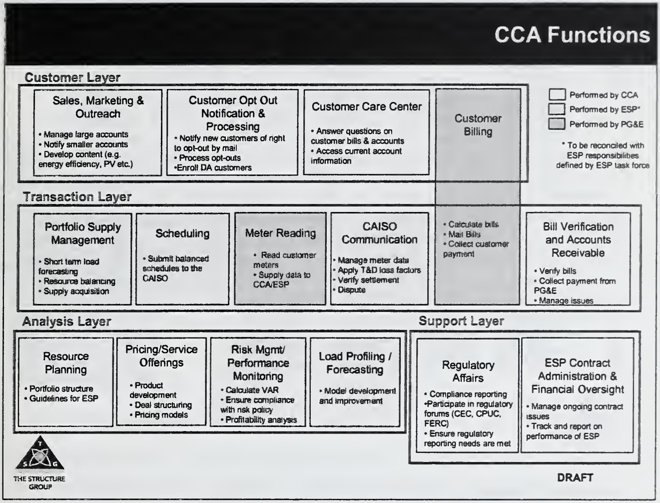
1.1 Background

The City of San Francisco has required that the San Francisco Public Utilities Commission (SFPUC) and San Francisco Environment (the Departments) develop a plan for implementing a Community Choice Aggregation (CCA) program in response to the California Community Choice Law, Assembly Bill 117, signed in 2002. The development of the CCA program requires substantial effort to identify and define the required functionality and program implementation planning for all aspects of CCA project administration and operation – this Appendix examines, at a detailed functional level, the scenario described in Chapter 7 where CCSF employees staff all "public face" functions of the CCA.

1.2 Objective and Scope

The objective of this report is to identify and describe the functions and processes needed to support the administrative and public face aspects, on an on-going basis, of the CCA. The aim is provide the SFPUC with an estimate of the resources required to administer the CCA program on a stand-alone basis, and assumes no leverage of other internal SFPUC resources or systems. The scope of this task is necessarily at a high level and results in initial estimates of the required headcount and support systems that require further requirement and analysis to gain a more accurate assessment of headcount and costs. Figure 1 illustrates the functions assumed to be conducted by the CCA to administer the program and how it would interact with PG&E and an ESP. This assessment does not incorporate the year 1 CCA start-up costs related to e.g. a significant Communications outreach program or the costs of Opt-Out Notification.

Figure 1: CCA Functions

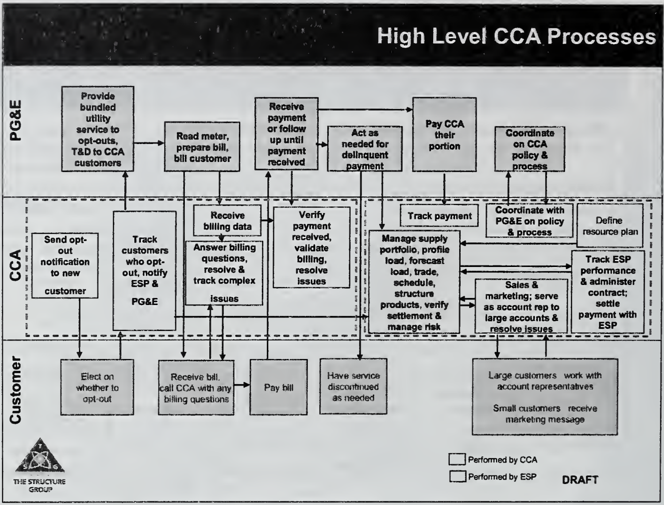


The Departments have identified the following major functions as core to a public face to potentially administer the CCA program:

- On-Going Customer Opt-Out Notification and Processing;
- CCA Customer Care Center;
- CCA Regulatory Affairs;
- Resource Planning, Portfolio Structuring, and Product & Service Development;
- ESP Contract Administration, Financial Management and Oversight;
- Sales and Marketing; and
- Potentially Bill Calculation, Presentment and Accounts Receivable Tracking.

Figure 2 illustrates the high-level processes within which these functions will operate based on potential CCA program planning efforts.

Figure 2: High-Level CCA Processes



In addition to the analysis of the functions for CCA administration, an outline has been included of the major implementation tasks and activities that would need to be completed to start-up this new organization. An overall timeline has been developed to give an indication of the amount of time it might take to get this CCA organization up and running.

1.3 Approach

Estimates of required headcount, needed systems and any major issues identified are captured in a brief summary for each major functions listed above. The estimated headcount shown is reasonable, but intentionally lean and is intended to be representative of the resource level required for the ongoing administration of the program.

This summary document identifies key assumptions, drivers and whether further study may be warranted to address critical issues or scenarios. This document is not intended to define detailed processes or organization, but provides analysis at the level of detail needed to determine general headcount requirements (e.g. the number of questions anticipated from customers on their bill is a driver for this analysis,). The document lays out the framework for estimating costs with explicit assumptions made. The framework has been provided and the assumptions can be challenged and changed further down the line as the requirements become solidified.

The major implementation tasks and activities to mobilize the CCA program have been outlined within three major functional phases:

- Organization Set-Up;
- Systems Implementation; and
- Organization and Systems Integration and Cutover.

Depending upon the degree of ultimate degree of involvement of CCSF in CCA implementation and operation these implementation tasks will require additional consulting/contracting support. At this stage, further analysis is required to create an estimate any additional consulting/contracting support required and hence these costs have not been included in the scope of this analysis. For example, the amount of external support will be highly dependent on the timeframe of hiring of internal resources and the timeframe for getting the CCA program up and running. An analysis has been included, however, of the needs for a Customer Information System (CIS) and the potential associated range of costs. CIS systems are complex and expensive undertakings and the report assumes a CIS, or sub-set of a CIS is required to support the identified CCA functions.

1.4 Definitions

Selected terms are defined as follows.

- **Customer** means any person or business that is taking electric utility service within the City and County of San Francisco.
- **CCA** means the City and County of San Francisco Community Choice Aggregation program, which provides customers with generation service using Utility Service for delivery.
- **Switching** means customers that are moved into CCA service from ESP or PG&E service or depart in a manner other than opt-out.
- **Opt-Out** means a defined process and opportunity when new customer accounts can elect to take Bundled Utility Service instead of participating in the CCA program. Opt-out will occur one time per new customer account and be offered with in a prescribed time frame of the new customer account being established.
- **Utility Service** means transmission and distribution service provided to customers by PG&E and does not include generation supply.
- **Bundled Utility Service** means transmission, distribution and generation service provided by PG&E. Customers that opt-out of or switch from the CCA program will likely be placed on Bundled Utility Service provided by PG&E.[1]
- **Supply** means electric generation supply that is provided under the CCA and be managed by an ESP on behalf of CCA.

[1] If the Direct Access option is re-opened by the California Legislature some customers might switch service to a Direct Access provider.

- **ESP** means Energy Service Provider that is responsible for managing the supply portfolio on behalf of CCA and includes Schedule Coordination and Settlement with the CAISO (California Independent System Operator).
- **Other Products and Services** refer to things sold to CCA customers other than basic electricity service (e.g. energy efficiency products, energy information services, energy conservation services, etc.).

1.5 Global Assumptions

The following assumptions govern the analysis.

Process Assumptions

- Upon the implementation of the CCA, all customers are part of the program. As new electric utility customers take service within the City and County of San Francisco (CCSF) they are automatically included in the CCA for the generation portion of the customer's electric utility service and are subject to the CCA generation rate applicable for the customer class and tariff.
- There will be a clear and efficient process for PG&E to notify the CCA of new customer accounts and closed customer accounts within the CCA jurisdictional service area.
- New customers connecting service with PG&E after the launch of CCA will be given notifications of their one-time right to opt-out within 6 months of their being in the CCA. Since new customers will be coming into the program on a routine and continuous basis, opt-out processing will group new customers by the month the account is established and provide one-time opt-out notification to these customers after some period (to be determined in Phase 2 of the CPUC CCA Proceeding) of the customer being part of the CCA. The opt-out notification process will therefore be a routine and continuous process executed once each month for those new customers that have been served by the program for some period – perhaps 6 months.
- Customers will be allowed to switch from the CCA to Bundled Utility Service, or direct access if re-opened however it is anticipated that the process of switching, will be restricted due to switching rules.
- The CCA program is administered at the customer level (e.g. an individual person or company associated with an electric service account), not at a meter or physical facility address level.
- These functions will evolve as other processes are more fully defined, including the responsibilities of the Energy Service Provider.
- Products and services offered to eligible customers under the CCA will largely be standardized per major customer class and tariff.
- Products and services will be consistent with existing PG&E electric utility tariff structures
- The responsibility for ensuring proper data exchange among PG&E, the ESP and the CCA for all data transactions (e.g. customer account information changes) will be the responsibility of the ESP.

Administration Assumptions

- The executive management of the CCA program will be determined outside of the scope of these functions. The executive management will be responsible for overall program direction, including establishing program guidelines, risk policies and performance metrics.

- General support functions, such as Human Resources and IT Support, will be scaled to accommodate these employees and will be addressed as part of the entire implementation plan.
- For purposes of this analysis, CCA functions will be administered with new stand-alone staffing and systems, without leverage of other groups.
- The headcount and system drivers are based on steady-state operations. The implementation of the systems, data conversion and start-up of programs are not included in resource estimates for these ongoing operations. This means for example that the year 1 Opt-Out Processing for the CCA is not included in the cost-estimates herein, neither is the year 1 Communication Outreach project costs.
- Adequate systems will be identified and implemented to support all functions and headcount estimates are based upon having adequate processes and systems in place.
- Office space and infrastructure (e.g. desk tops) to house new employees associated with the CCA administrative program will be addressed as part of the entire CCA implementation plan.
- Wages will be based on the prevailing SFPUC wage rule.
- Any population growth or decline within the CCSF under the jurisdiction of the CCA will have a negligible effect on this planning horizon.

1.6 Other Issues Identified

In the course of this analysis, some other issues were identified and captured here for further consideration or clarification at a later stage of the implementation process (e.g. detailed process and design purposes). The issues are as follows.

Program Direction

- The extent of non-standard product offerings or terms will affect the complexity of many of these functions, from Sales and Marketing to the ESP portfolio risk management to the billing requirements.
- Credit responsibility needs to be clarified. If Credit requirements for generation supply are managed by the CCA, as opposed to the ESP, then additional headcount and associated capitalization of the CCA may be required.
- The scope of any settlement verification performed by the CCA needs to be clarified further. This may involve validation of ESP settlements with suppliers and CAISO as well as payment and accounts receivable processes on the customer side.
- The potential of linking a CCA call-centre operated by CCSF employees to an ESP customer information system should be investigated. This option may allow CCSF to operate a full-service call centre without also requiring a CCSF CIS system. However the reliance this may place upon a continued business relationship with one particular ESP means the option of third-party operation of a CIS system should also be explored.

- If the CCA institutes its own exit-fees or switching rules to be applied to CCA customers this may complicate various functions and potentially add a new layer of tracking and administrative costs for the CCA.

Process Topics

- This study has assumed that PG&E will be responsible for collecting payment from the customers, but further definition is required as to how the CCA will ensure such effort and what rights the CCA will have in non-payment cases, arrangements for no-pay/bad debt, payment allocation priority[2] and collection activities (this important issue is to be resolved in Phase 2 of the CPUC CCA Proceeding).
- CCA will be accountable for payment to the ESP for generation supply on a monthly basis (industry standard). Bill cycles for CCA customers are not consistent with ESP payment so cash flow and timing will be critical. Moreover, to the extent there are non-payment issues from customers, potential for significant cash flow and coverage issues exist. Product pricing or creation of a working capital account must take these issues into account to provide reasonable cash coverage.

2. FUNCTION 1: ON-GOING CUSTOMER OPT-OUT NOTIFICATION AND PROCESSING

2.1 Function Description

After the mass transfer at the start of CCA service, it is assumed there will be ongoing requirements to notify new customers of their right to opt-out, to inform them of the opt-out provisions and to facilitate any customer switching, if allowed. For new customers entering the CCA jurisdiction, it is assumed the customer will be automatically enrolled in the CCA, but have a one-time opt-out notification after six months of enrollment within the CCA program. The signed opt-out responses will need to be processed.

This function will require:

A. receiving customer account data changes from PG&E and updating the CCA mailing list;
B. sending monthly mailing to new customers notifying them that they are in the CCA program and advising them of the opt-out provision and time frame (e.g. they will receive opt-out mailing after six months of their establishing new electric service);
C. tracking notification period and customers that are to be notified at the six month service point;
D. processing the mailings including follow-up required with the customer to ensure a complete opt-out request;

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[2] Refers to priority of payments from funds received – e.g. PG&E distribution charges covered first v. CCA generation charges.

E. tracking responses and processing of responses;
F. preparing a list of those who have opted out of the CCA;
G. capturing the necessary information to adjust the daily load curve, demand and energy requirements for the CCA portfolio by the number of customers opting out (by class and tariff) and providing that information to the ESP for procurement portfolio adjustments;
H. submitting the opt out list to PG&E in the required format; and
I. verifying the opt-out list against the billing list from PG&E.

To the degree there is a peaking workflow in this function (e.g. seasonal turnover or such), temporary contract help will be utilized to provide peaking capacity.

This function could report up through the Call Center. The Call Center size could absorb the peaking nature of the notification function and employees would have similar skill sets.

2.2 Headcount Drivers

The assumptions driving headcount are:

- 351,000 total customers (comprised of 321,000 residential customers, 28,000 small-medium commercial customers and 1500-2000 large customers) will have negligible growth over the next five years for initial CCA project administration;
- Of the 351,000 total customers, 321,000 existing residential customers with a 25% annual turnover rate
- Of the 351,000 total customers, 28,000 small-medium commercial customers and 1500-2000 large customers will have lower turnover rate e.g. 12% annual turnover;
- 25% annual residential churn, and 12% annual commercial/large customer churn, will result in approximately 7,000 customers per month requiring notification (pending outcome of rules on one-time opt out requirements and switching)
- Billing cycle and meter reads are evenly distributed through the month;
- Customer switching will be minimal and rules will be prohibitive;
- Bilingual requirements will be met;
- Oversight of the mailing list will require minimal time;
- Printing, mailing and processing of one-time opt-out notices for new customers will be done every month;
- Printing and processing will be outsourced;
- 700customers per month (i.e. 10% of the customers estimated to receive notification of some type) will opt-out or switch;
- CCA will receive questions through the general Call Center function;
- Communication with PG&E and ESP will be required.
- A key uncertainty in the assumptions is the degree to which new customers turnover represents existing customers who move within the CCA. New accounts created by residential or business moves within the CCA should be assumed to be existing CCA customers and hence will not incur further opt-out processing.

Estimated headcount:

- 1 FTE supervisor
- 3 FTE clerks (temporary contract help or call center representatives may also be used)

2.3 System Drivers

The required capabilities are:

- Mailing database and tracking
- Community Choice Aggregation Service Request (CCASR) submission
- Website information customers for general information
    - Frequently Asked Questions (FAQ)
    - General program and educational information

System needs:

- Customer Information System (CIS)
- CCASR submission via Visual Basic (VB)

3. FUNCTION 2: CCA CUSTOMER CARE CENTER

3.1 Function Description

CCA service will require customer care capabilities to field billing and account inquiries and support the opt-out and switching processes. The customer care representatives may also field some general program questions and direct customers to general information about the CCA program. The CCA Customer Care Center (CCC) will support in-bound calls only, but the customer care representatives may provide promotional information about other products and services at the end of an in-bound customer call. The customer care representatives will require easily accessible customer and general program information, including access to all customer-billing records and any customer information that may be maintained by the ESP (e.g. current load profile for larger customers that are on TOU tariffs and that may have real time or daily interval meter data available to the ESP). The customer care representatives will have the ability to forward or transfer complex questions or issues to Account Representatives for the larger customer classes. The CCC should have the flexibility to adopt the capability to field questions submitted by email through a CCA website. The website may contain general CCA program information and answers to frequently asked questions.

3.2 Headcount Drivers

The assumptions driving headcount are:

- 351,000 total customers (comprised of 321,000 residential customers, 28,000 small/medium commercial customers and 1500-2000 large customers) will be billed every billing cycle;
- 10% of existing customers (35,100) in the mass transfer will opt-out;
- 315,900 existing customers will remain under CCA service;

- Billing cycle and meter reads are evenly distributed through the month;
- There will be no walk-up customer assistance available;
- 1 customer in 50 will call monthly with a question resulting in 6,300 calls per month or approximately 250 calls per day;
- Each call will average a duration of 7 minutes (420 seconds) with a 1 minute wrap up time;
- 80% of calls will be answered within 20 seconds;
- Available work hours will be limited by 10% shrinkage (e.g. vacation, sick-time, training);
- Customer care representatives will field these calls with scripted information;
- There will be approximately 1 senior customer care representative for every 4 customer care representatives;
- Senior customer care representatives will have additional expertise to field complex questions;
- A supervisor will be on hand to address complex questions and assure issue resolution for major accounts and communication with account representatives;
- The supervisors will absorb "shrinkage" (vacation, sick-time etc) estimated at 10%;
- The call center hours will be 8 AM to 5 PM Monday through Friday (consistent with SF water hours);
- Bilingual requirements will be met;
- Technical support will be available at all times and will be met through global IT Support group.

The existing staffing and the call loading relative to the SFPUC water utility service in San Francisco is a reasonable benchmark for the CCA CCC. The following are a few of the key metrics from the water utility service customer care:

- 180,000 customer accounts
- 7 dedicated call center representatives
- 3 customer service representatives to serve walk up customers and to provide overflow capacity for the other call center representatives
- 400-500 inbound calls per day; a maximum peak of 600 calls;
- 3-4 minute average call duration
- 5 account representatives handle larger customers with more complex accounts
- Operation from 8:00 AM to 5:00 PM, Monday through Friday
- 15 active phone lines.
- System used for Call Management is Avaya

The estimated CCC headcount is tested with Erlang traffic modeling methodology based on the call duration, call frequency and response time described above. Erlang traffic models can be used to estimate the number of lines required in a network and staffing requirements for call centers. The Erlang B traffic model estimates the number of lines required during the busiest hour, assuming blocked calls are cleared, and associated staff requirements. The Erlang C model estimates the staff requirements assuming that blocked calls stay in the system in a queue. The Erlang model assumes that the calls

arrive randomly in a Poisson distribution. As a result, the staffing estimate may fall short during extreme peaks, (an extreme peak is likely during any mass Communications outreach projects and also, of course during year 1 Opt-Out Processing)[Source: http://www.erlang.com and http://www.diagnosticstrategies.com/].

The following table shows the sensitivity call center staffing results for different input assumptions. Due to the relatively small size of the call center, slightly more staff may be required to absorb peak call periods or lower performance against the answering target may need to be acceptable (i.e. a call center with 100 representatives will absorb peaks better than one with 10 representatives). Again this staffing is assumed to be that required during a CCA steady state approach, however during year 1 numerous questions can be expected about the CCA program – particularly in response to the Opt-Out notices.

Table 1: Sensitivity Analysis of Call Center Staffing

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Average call duration (minutes)	7	4	5	7
Number of calls per day	250	450	600	600
Call answering target	80% of calls within 20 seconds	80% of calls within 20 seconds	80% of calls within 20 seconds	80% of calls within 20 seconds
Shrinkage	10%	10%	10%	10%
Number of representatives	9	7	14	18
Number of phone lines	11	9	16	21

Estimated headcount:

- 9 FTE customer care representatives (8 reps with 10% shrinkage requires 9 reps total [8 reps / (1-0.1)] to be absorbed by supervisors.
- 2 FTE supervisors
- 1 FTE manager
- 1 FTE administrative assistant (may also assist with opt-out notification process)

3.3 System Drivers

The required capabilities are:

- Shared access to billing records and customer information
- Scripted information on frequently asked questions
- Issues management for complex questions
- Issues resolution tracking and issue close out tied to CIS and CRM systems
- Automated phone system
- 11 trunks (phone lines)

- Website for general information and for customer self help:
    - Guided Self Help and "Frequently Asked Questions" (FAQ) functionality
    - Web based customer inquiry and issue posting
    - "Contact request" and email question capability

System needs:
- CIS/CRM functionality
- Call Center software (Avaya or comparable)

4. FUNCTION 3: CCA REGULATORY AFFAIRS

4.1 Function Description

The CCA program will require participation in ongoing regulatory proceedings at the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and potentially the Federal Energy Regulatory Commission (FERC). The regulatory group will ensure that the CCA is up to speed on any regulatory changes; provide guidance on changes to the necessary forums; and provide advocacy functions in appropriate forums for issues important to the goals and objectives of the CCA. The regulatory group will provide regular briefing to management and any group within the CCA that may be affected by regulatory changes. The regulatory group will also be responsible for providing any required compliance reporting to the CPUC or the CEC and CAISO on the CCA program. The regulatory group may provide coordination and communication liaison with PG&E regarding policy and practice issues associated with the CCA.

4.2 Headcount Drivers

The assumptions driving headcount are:
- Required regulatory meetings will generally not conflict in schedule;
- Travel will be primarily limited to Sacramento and San Francisco;
- Any required legal assistance will be met through existing legal support functions.

Estimated headcount:
- 1 FTE regulatory analyst
- 1 FTE senior regulatory analyst/manager
- 0.5 FTE administrative assistant

4.3 System Drivers

The required capabilities are:
- Adequate data capture for regulatory reporting
- Standard office software

System needs:
- Compliance Reporting database (capture of CCASR information, ESP data)

5. FUNCTION 4: RESOURCE PLANNING, PORTFOLIO STRUCTURING & PRODUCT AND SERVICE DEVELOPMENT

5.1 Function Description

The CCA program will include the development of a resource plan that identifies and captures the types, quantity and timing of generation resources needed to meet the product and service objectives of the CCA program as defined by the CCA executive management. In addition, value added or energy efficiency-based products and services to compliment the energy commodity products will need to be identified, developed and implemented.

These functions will be supported within the CCA organization and coordinate closely with the CCA Sales and Marketing functions as well as with the ESP that is managing the energy supply portfolio. The CCA Resource Planning, Portfolio Structuring and Product and Service Development function ("CCA RP group") will identify the types of generation resources and portfolio mix that are desired for the overall CCA energy portfolio and the types of energy products and structures that may be offered[3] (e.g. "green energy" mixes, wind-only, price risk management services, etc.) along with any structured options or pricing that may be available or appropriate. The CCA RP group will work closely with the ESP(s) to assure that energy products and services desired can be supported with the portfolio, within the pricing ranges and defined risk policies; or will work with the ESP to determine what changes to the portfolio might be needed to support the desired energy products or services.

The CCA RP group will also be responsible for identifying and developing non-commodity ("value added") products and services that are consistent with the overall goals and objectives of the CCA program. These products and services will be complimentary to the energy commodity offerings and will be of value to the CCA program customers, such as energy conservation and efficiency programs, energy information services, alternative small-scale generation/cogeneration/distributed generation, rate evaluations, and bill payment/financing programs.

5.2 Headcount Drivers

The assumptions driving headcount are:

- The breadth and degree of complexity associated with the energy products desired to be offered, the resulting generation portfolio mix required and the complexity associated with the ESP successfully creating the needed supply portfolio is assumed to be reasonably simple and limited to a maximum of 3-4 energy

[3] We assume that the detail work on portfolio structure, components, and ESP responsibilities are being developed by the ESP Functionality Team. It's finding will need to be incorporated or referenced in this effort.

products[4] and that the majority of the product structuring is supported by the ESP with CCA staff providing guidance, oversight and approval;
- Number of non-energy products and services to be offered is assumed to be limited to 4-5[5]of standard design (e.g. energy audits, energy efficiency advice and reference to approved contractors with structured service offerings, etc.);
- Selling processes for non-energy products and services would be via the account reps in the CCA Sales and Marketing group leveraging the marketing analysts and outreach specialists;
- The timing of offerings is assumed to be evenly distributed;
- Web site commerce and/or mailers are used for products (e.g. lighting, appliances, etc);
- Energy commodity products are available in the market place with underlying structures that can be decomposed or managed within the CCA portfolio (by the ESP) in a cost effective manner, including risk premiums. Scarcity of market-based supply products will require greater creative and monitoring effort working with the ESP to meet the goals of the CCA program;
- Customer load data is readily available and product and service interests are easily defined and measured through supporting efforts within the Sales and Marketing groups.

Estimated headcount:
- 2 FTE for energy and value added product and services planning and development
- 0.5 FTE manager (may be shared with ESP contract management)
- 0.5 FTE administrative assistant

5.3 System Drivers

The required capabilities are:
- Access to customer load data, product interest, market price information
- Customer interest and product research available for product and service descriptions via the CCA Sales and Marketing organization.
- Standard office software, including spreadsheet-based tracking and modeling tools

System needs:

To be defined further in conjunction with ESP system responsibilities.

6. FUNCTION 5: ESP CONTRACT ADMINISTRATION AND FINANCIAL OVERSIGHT

[4] For purposes of the analysis, the initial offering and steady state operations that drive the FTE and cost estimates are constrained. It is reasonable to assume that energy product offerings will evolve and change based on customer acceptance and value but that a mix of 4-6 products offered at any time is reasonable.
[5] The number here refers to new products and service, the oversight and evaluation and change out of the product mix over time, based on customer acceptance and value.

6.1 Function Description

The CCA program will require management and oversight of the services provided by the ESP that will be charged with managing the supply portfolio and the delivery of generation supply to CCA customers. The Contract Administration function will initially participate in development of a contract with an ESP and subsequently manage ongoing questions that may arise. Legal expertise will be required periodically to assist with contract interpretation.

This function will be further defined as the larger CCA program is determined, but will be greatly influenced by:

A. what functions are ultimately assumed by the ESP;
B. by what products will be marketed and sold to the large customers;
C. who manages customer and supplier credit risk; and
D. what other functions are outsourced, if any, to facilitate the CCA program.

As part of the oversight of the CCA service, it will be necessary to report on the overall performance of the program. This group will track and analyze performance of the ESP relative to the objectives of the supply portfolio and make recommendations to management regarding changes or opportunities associated with the management of the supply portfolio. This group will provide periodic reports to city officials identifying any issues or potential risks in the administration of the program and estimating financial impacts of any changes in the program. The full scope of this function will be a direct function of the responsibilities defined and assigned to the ESP and will need to be defined further as the CCA program is developed.

This group will be responsible for ESP payments and settlements associated with the energy supply managed by the ESP, as well as any charges associated with ESP services.

6.2 Headcount Drivers

The assumptions driving headcount are:

- The ESP functions (as shown in CCA Function diagram and to be reconciled with the ESP responsibilities defined by the ESP task force) will be outsourced, other functions will be accommodated in-house;
- This group will meet both routine periodic reporting and ad hoc reporting;
- The ESP will be managing the supply portfolio with minimal responsibility passed to the CCA;
- Portfolio performance objectives (according to overall risk policy and direction determined by the executive management) will be well defined and measurable by CCA independent of the ESP;
- The data requirements for ESP audit will be well defined in the ESP agreement;
- The Sales and Marketing group will primarily sell standardized, non-complex products to large customers; small commercial and residential energy products will be standardized with limited product choice to customers initially;

- Billing and settlement data is readily available from the CCA billing group, the ESP contract and settlement processes are well defined and appropriate data is supplied from PG&E and CAISO such that charges can be determined with reasonable accuracy and in a timely manner;
- Minimal recharging or corrections are required for ESP settlements;
- Reporting on any other outsourcing contracts will be minimal.

Estimated headcount:

- 3 FTE contract, finance and reporting analysts
- 0.5 FTE attorney
- 1 FTE manager
- 1 FTE administrative assistant

6.3 System Drivers

The required capabilities are:

- Access to ESP supply and settlement data as well as contract terms and conditions as needed to assist with any contractual interpretation issues.
- Standard office software, including spreadsheet-based tracking and modeling tools

System needs:

To be defined further in conjunction with ESP system responsibilities.

7. FUNCTION 6: SALES, MARKETING AND OUTREACH

7.1 Function Description

CCA service will provide general customer service with information on rates and programs. The Sales and Marketing group will develop and maintain customer relationships with the largest customers that are represent substantial CCA portfolio load. Account representatives for large customers will serve as the single point of contact for all functions (e.g. billing questions, product offerings) and will serve as the liaisons with PG&E. The large customer account representatives will understand the market and potential products to serve the market. The Sales and Marketing group will target the small to medium commercial customers with periodic mailings. The small customers will receive less frequent information mailings.

The content of these marketing efforts will need to be developed and customized to several customer sub-groups. These marketing specialists will also be responsible for assessing the effectiveness of the content; adjusting the messages as needed; managing the distribution of the content to all required, including the call center; overseeing the production of all materials; and evaluating the overall program. In addition to these marketing efforts, community outreach and education needs will be met.

The Sales and Marketing function is very dependent on the nature of the products that will be offered and on the strategy decided upon by executive management. Changes in products or strategy will have a large impact on headcount. If non-standard products are offered or if customized terms are adopted, then the Sales and Marketing group will not only require greater head-count, but there will be implications for other functions and support systems, such as contract administration, reporting, billing preparation and ESP responsibility (e.g. product pricing, deal structuring and risk management). Other important products and service offerings like energy efficiency, demand response, and distributed generation facilitation) will also be incorporated into the activities of this group.

7.2 Headcount Drivers

The assumptions driving headcount are:

- 100 very large customers will be targeted with regular sales activity;
- 5 marketers will be dedicated to the top 100 customers;
- 1500-2000 large customers will be served with account representatives;
- 1 account representative will have 100 large accounts;
- Product offering will be standard products with consistent pricing terms;
- Deal structuring, customer and supplier credit and deal risk will be part of ESP portfolio management;
- 28,000 small to medium sized commercial customers will require periodic product and service offering mailings;
- The marketing message will relatively consistent across commercial groups;
- Outreach and education efforts will not have conflicting events.

Estimated headcount:

- 5 FTE senior marketers/account representatives
- 20 FTE account representatives for large customers
- 1 FTE supervisor of account representatives
- 3 FTE marketing specialists and outreach coordinators
- 1 FTE supervisor of outreach
- 1 FTE group manager
- 2 FTE administrative assistants

7.3 System Drivers

The required capabilities are:

- Customer relationship tracking, including deal history
- Tie to CIS
- Website dissemination of information
- Standard office software including publication software for publication development

System needs:

CIS/Sales and Marketing Module

8. FUNCTION 7: BILL CALCULATION, PRESENTMENT AND ACCOUNTS RECEIVABLE MANAGEMENT

8.1 Function Description

The CCA program will potentially oversee rate ready billing and provide generation rates by PG&E electric rate schedule to be used in the CCA billing. The utility will read the meter, calculate the bill, mail the bill and collect the customer payment. The utility will be responsible for following up with the customer until payment is received. The ESP, will receive the daily meter read records from the utility along with any billing information associated with monthly meter reads (e.g. small commercial and residential) so that the ESP can adjust the daily supply forecasts and manage the supply portfolio, including any necessary interaction with CAISO, PG&E or other market participants

The ESP will receive monthly individual customer billing summary statements from PG&E which will include customer specific meter read data, billing determinates for the applicable period, total charges, and date processed and sent. Data shall be in a form that is readily imported to CCA systems for direct posting to the CCA CIS prior to the customer receiving the bill.

The CCA will have systems to monitor and assure that all customers under the CCA have been billed, that the bills appear reasonable. The system will flag missing bills, suspicious data or erroneous bills. The CCA will develop systems to spot check bill-ready billing to ensure that PG&E's processes are accurate.

PG&E will provide the CCA with daily files updating bill payments received, noting any delinquent billing issues. Account representatives shall readily import files to the CCA systems to support CIS/CRM systems and access.

If non-standard products are sold to large customers then the CCA may need to manage more complicated information for bill ready billing. For purpose of this analysis it is assumed that rate ready billing is sufficient for the majority of CCA customers.

8.2 Headcount Drivers

The assumptions driving headcount are:

- 351,000 total customers (comprised of 321,000 residential customers, 28,000 small/medium commercial customers and 1500-2000 large customers) will be billed every billing cycle;
- 10% of existing customers (35,100) in the mass transfer will opt-out;
- 315,900 existing customers will remain under CCA service;
- Billing cycle and meter reads are evenly distributed through the month;
- All customers will only require rate ready billing;

- Billing data will be imported to CCA CIS and administrative systems;
- Billing issues requiring analyst time will be exception based and generated by applications and systems;
- Account representatives will assist in the resolution of issues that are not based on PG&E billing;
- The utility will have responsibility to collect payment for the bills;
- The process for no pay situations will be well defined;
- Customer billing will be spot checked by customer/rate class.

Estimated headcount:

- 4 FTE billing analysts (billing verification, issues resolution, receivable tracking)
- 1 FTE manager

8.3 System Drivers

The required capabilities are:

- Shared CCA and ESP access to billing information
- Data transfer and confirmation
- Calculation and settlement verification
- Verification that all customers are billed
- Data capture for reporting
- Shared access to billing records and customer information
- Adequate reporting and data capture

System needs:

- Initially, database and data tools that support analysis and tie to CIS

More complex utility billing capability should custom products or other services be offered that are not compliant with PG&E "bill ready" billing will require additional system support.

9. ONGOING COSTS

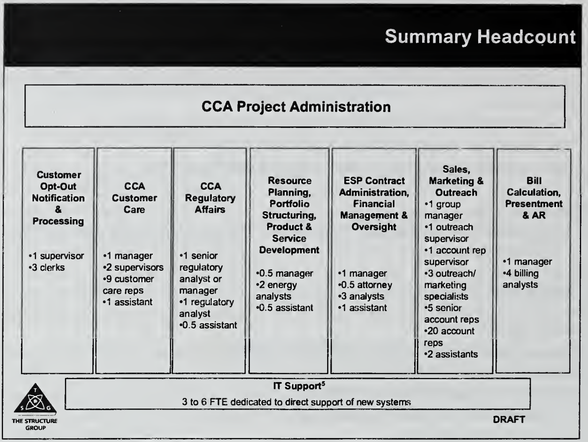
The two major cost categories for operating the CCA functions are headcount and IT costs and these have been outlined below.

9.1 Headcount Costs

A summary of the required headcount to support the functions described above is depicted in Figure 3.[6]

Figure 3: Headcount Summary

[6] The IT support listed here is dedicated to support the new systems required for the functions described above. The need for additional IT personnel for desktop support and other general functions is not included here, nor are other global support functions, such as HR or other corporate functions.



Attachment 1 provides a tool to estimate ongoing CCA headcount costs based on city employee job classifications, and salary levels staffing, and overhead burden assumptions. Challenging the assumptions made on headcount numbers can change the derived costs from the spreadsheet.

9.2 Ongoing Systems Costs

There may be opportunities for the CCA to leverage existing systems and IT support used by the water utility or to leverage the systems to be required by the ESP. For this purpose, it is assumed that new, stand-alone systems support will be required. Based on the initial analysis of the above functions, we have assumed the following systems will be required:

A. A third party Customer Information System (CIS) to manage customer accounts and track issues.
B. A third party Call Center system to manage call flow and scripted content.
C. A number of pc custom applications to manage transactions and communications (e.g. CCASR) and to store data for reporting and analysis.
D. Website to provide information to customers.

The costs of maintaining these systems can be broken into two components:

- IT Headcount: to support and maintain the systems e.g. enhancements, reports etc.

- Third Party Maintenance: the ongoing licensing and maintenance of third party systems is typically 15% to 20% of the initial licensing fee. Obviously there are many different pricing options available for third party software (e.g. leasing systems, paying on a transaction basis etc.). For the purposes of gaining insight to the potential ongoing costs, the standard license fee and maintenance approach is the most simple and has been used here.

IT Headcount

Assuming that the CCA will need an additional 3 to 6 IT FTE's to directly support the new systems in steady state operation, a range of costs can be derived and have been included in the overall headcount analysis. This does not include any increase in overall corporate IT support for desktops etc.

Third Party Maintenance

Assuming third party license fees are in the range of $2 to $8 million (see Implementation Activities, CIS Costs), this would result in an annual fee of between $0.3m and $1.6m. This range is large since the prices for CIS systems vary markedly and are based on many variables e.g. functionality needed, number of seats, etc.

10. Overview CCA Implementation Activities

Assuming CCA undertakes the variety of tasks identified in this Appendix this section gives an overview of the major tasks and timeframes required to implement the necessary systems and staff for CCA program administration. An overall timeline has been developed to give an indication of the amount of time it might take to get the proposed organization up and running. More detailed analysis would need to be completed to gain a more accurate assessment of the workload and timeframes.

The major implementation tasks have been separated into three major phases of work:

- Organization Set-Up
- Systems Implementation, and
- Organization and Systems Integration and Cutover.

The three phases of work have been broken down into a series of major tasks and activities described in the sections that follow on each phase.

The initial set-up and implementation of the CCA functions will require additional consulting and contracting support (e.g. program management, vendor management etc.). There are many variables that need to be considered in determining the level of outside headcount (e.g. speed in hiring internal staff, experience of internal staff in systems implementation etc.). The additional headcount and costs associated with the initial set-up and start-up of the program are not included in the scope of this report and further analysis is required.

A brief analysis, however, has been included of the range of costs for buying a CIS system that would need to be installed to operate the CCA. The CIS software will be a major cost item for the CCA implementation and some initial estimates have been provided.

10.1 Organization Set-Up

The organization required for the ongoing CCA administration has been outlined above and we have based the following activities on this organization design. The key steps for implementation are described below.

Hire Key Managers

A. Organizational structure and key functions are developed and agreed upon.
B. Charter and create a small initial Staffing Team that reports to the CCA director that is responsible for the identification and hiring of key management positions (e.g. Manager of Customer Care Center, Manager of Sales and Marketing, etc.). The Staffing Team would be responsible for the following:
    a. Develop position descriptions and position qualification specifications, and compensation bands for key management roles.

   b. Prioritize the key management positions in terms of hiring order and desired timing. Develop dependencies and contingency plans as appropriate prior to starting the recruitment process.
   c. Identify hiring responsibilities and key decision makers. Assure access to these key individual's calendars and have authority to schedule interviews, review sessions and selection meetings.
   d. Develop a recruitment plan covering both internal and external candidates,
   e. Develop management training requirements and schedules for these key positions pending hiring
   f. Screen potential candidates' resumes and develop candidate pool for each key position. Schedule and coordinate interviews and follow up communications with candidates.
   g. Work with hiring manager(s) to evaluate candidates and make selection. Coordinate offer letters, hiring negotiations and final acceptance.

C. Key management positions are filled.
D. New managers go through orientation and training program.
E. Staffing Team works with new managers to define organizational needs for each functional area and provides support as described above for the next round of hiring.
F. Staffing Team stays involved in the process to assure consistent application of hiring criteria, offer structure, etc.

Hire Employees

The key managers will be responsible for hiring the employees for their group and overseeing the development of appropriate detail processes and job-specific employee training. The key managers will work with the Staffing Team to define the organizational needs and work within established guidelines for hiring employees.

Train Employees

Once the employees are hired, the key managers will be responsible for the administration of the orientation and training program for the employees. The training program will need to be well defined and in accordance with CCSF guidelines. The trained employees will take part in the final process and systems testing. Their participation in the testing process will facilitate the cutover and knowledge transfer processes.

Dependencies

The key managers will be resources on the Systems' Implementation team and Organization and Systems Integration and Cutover team, serving as subject matter experts for key functions. The key managers will also be involved in approving the overall implementation plan with respect to its being comprehensive and reasonable with adequate resources and timeframes and milestone deadlines.

As the program gets started, a Manager within the Sales, Marketing & Outreach group will be a first priority in the hiring process in order to provide communications to customers and leadership as the program gets started. Due to their role in the Systems Implementation phase, the Manager of CCA Customer Care; the Manager of ESP Contract Administration, Financial Management & Oversight; the Manager of Bill Calculation, Presentment & Accounts Receivable are the first priority for hiring, followed by the Manager of Resource Planning; and Manager of CCA Regulatory Affairs. All of these positions need to be filled quickly and efficiently as the program gets underway. The Staffing Team will develop the initial training plan and it will be used as a guide for the project team and to define how the training will be delivered. The business stakeholders will need to be prepared and a project communication plan should be used to build awareness, support and acceptance of the project internal to the CCA and with customers.

10.2 Systems Implementation

The Systems Implementation will include the Customer Information System (CIS); call center application, and other custom systems. Successful Systems Implementation is dependent on having established clear requirements and well defined processes and on the availability of adequate resources dedicated to the effort.

CIS and Call Center Applications

The CIS and Call Center implementation will include:

A. Review and approve systems requirements based on approved processes, data inventory, required functionality, etc.
B. Develop specific requirement and functional specifications, develop request for proposal (RFP) or other procurement plan, and facilitate competitive acquisition processes.
C. Select CIS and call center application;
D. Procure CIS and call center application according to CCSF procurement rules;
E. Complete statement of work and define milestones and deliverables;
F. Establish project team, define governance; and assign responsibilities;
G. Define change management process and approval steps;
H. Identify risks and their mitigation;
I. Finalize system requirements;
J. Complete detail design;
K. Establish hardware requirements and environment (test and production);
L. Install (including modifications, interfaces and reports), configure and test systems;
M. Complete initial data conversion (conversion, data extraction, data mapping and documentation);
N. Transfer knowledge;
O. Sign-off with acceptance.

The Statement of Work will cover the specific tasks, strategies for the various tasks (e.g. conversion, testing), responsibilities, status reporting requirements, deliverables

requirements for requirements documents, design documents, delivered code (e.g. reports, training materials, completion milestones (e.g. training, testing) and cutover to production).

Custom Applications

The custom applications implementation will include:

A. Review and approve systems requirements based on approved processes, data inventory, required functionality, etc.
B. Develop specific requirement and functional specifications, develop request for proposal (RFP) if needed or other procurement plan and facilitate process;
C. Select vendor(s) and procure according to CCSF procurement rules;
D. Complete statement of work, define milestones and deliverables and gain management approval;
E. Establish project team, define governance; and assign responsibilities;
F. Define change management process and approval steps;
G. Identify potential risks, metrics and possible mitigation alternatives;
H. Finalize system requirements;
I. Complete detail design for custom systems;
J. Establish hardware requirements and environment (test and production);
K. Install (including modifications, interfaces and reports), configure and test systems;
L. Transfer knowledge;
M. Sign-off with acceptance.

The Statement of Work will cover the specific tasks, strategies for the tasks, responsibilities, reporting requirements and deliverables as discussed above.

Dependencies

As part of the Systems Integration planning, the external dependencies that may affect the schedule will be identified, such as the hiring timeline for key managers and employees; defined procurement cycles and approval requirements; and PG&E and ESP integration. CIS implementations are lengthy and complex with data inventory and integrity, data mapping and data conversion often being a key factors. For planning purposes we have assumed that the CIS can be implemented in an 18 to 24 month timeframe. However it is important to highlight that this would be one of the major variables in determining the timeframe and costs of starting up the CCA. The custom applications, including Visual Basic and database systems, will be completed alongside the CIS and call center implementation.

10.3 Organization and Systems Integration and Cutover

The Organization and Systems Integration and Cutover phase will include the integration and testing of systems and processes and ensure the cutover of accounts 120 days (the initial opt-out time period) after the go-live date. This phase will be highly dependent on

integration readiness of the ESP systems (and ESP system requirements defined in their RFP) and on working with PG&E for the cutover.

This phase will include:

A. Integration and testing of processes and systems;
B. Data migration; and
C. Cutover and Post-Cutover Support.

Integration and Testing of Processes and Systems

These tasks will include the integration of the CIS and call center applications with the custom applications, the ESP systems, PG&E and others as needed. It will also include tasks to inventory, evaluate, test and refine the processes and timeframes for smooth business operations. A detailed testing plan will be created as part of the implementation plan and integration testing will be carried out. As part of this, potential risks (e.g. system, data, process, organization, etc.) and their potential mitigation will also be identified in the implementation plan. These tasks will require working with the ESP, PG&E and others to successfully integrate test and deploy the CIS and call center applications with custom applications.

Data Migration

The data migration tasks can be complicated and time consuming for the implementation of the CIS. At a high-level, the data will need to be inventoried, defined and extracted from the legacy system managed by PG&E and converted into the required format to populate the CIS. Support by PG&E experts on the legacy system will be necessary. The responsibilities for inventory, assessment and cleaning up the data if needed will need to be defined. The testing plan will need to address the testing requirements for the data integrity and migration tasks.

Cutover and Post-Cutover Support

The cutover tasks will ensure that the transfer of accounts 120 days (the initial opt-out time period) after the go-live date happens smoothly. Post-cutover support will be required for the first few months of live operation to address glitches that will inevitably arise. Complete knowledge transfer and acceptance sign-off will occur at the end of these tasks.

Dependencies

Due to the nature of the tasks, the Organization and Systems Integration and Cutover phase is highly dependent on all aspects of the project and on all parties involved. It will require participation by PG&E and ESP resources and will require their systems be fully tested and ready. Success of this phase is dependent on the quality of the data and any issues with the data migration. This phase is also dependent on the turnaround time of issues that are identified and on the resolution of problems that arise.

10.4 Summary of Activities

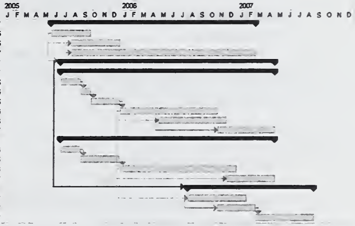
The following chart shows a high-level draft project plan. This purpose of this chart is to provide an indication of the time frames that would be involved in project implementation. As highlighted above there are many factors and unknowns that will determine the actual length of the project and some of these are summarized as follows:

- Amount of external help utilized on the project
- Complexity of CIS implementation
- Procurement and hiring guidelines
- Integration with ESP
- Integration with PG&E
- Commitment and availability of key internal resources

This project schedule is aggressive and provides for implementation in just less than 2 years. The sub-tasks under the CIS & Call Center Applications and the Custom Applications (listed in the Systems Implementation section above) have been summarized and grouped for this purpose.

Figure 4: Draft Project Plan

ID	Task Name	Start	Finish
1	**Staffing & Training**	**Wed 6/1/05**	**Wed 2/28/07**
2	Hire Key Managers	Wed 6/1/05	Fri 9/30/05
3	Hire Employees	Mon 8/1/05	Fri 12/30/05
4	Train Employees	Mon 8/1/05	Wed 2/28/07
5	**Systems Implementation**	**Fri 7/1/05**	**Mon 4/30/07**
6	**CIS & Call Center Applications**	**Fri 7/1/05**	**Mon 4/30/07**
7	CIS Selection & Procurement & SOW	Fri 7/1/05	Wed 8/31/05
8	Project Charter, Team and Responsibilities	Thu 9/1/05	Fri 9/30/05
9	Finalize requirements & detail design	Mon 10/3/05	Fri 12/30/05
10	Install, configure and test	Mon 1/2/06	Tue 10/31/06
11	Data conversion	Mon 5/1/06	Thu 11/30/06
12	Knowledge transfer	Wed 11/1/06	Mon 4/30/07
13	**Custom Applications**	**Fri 7/1/05**	**Mon 4/30/07**
14	Selection, Procurement & SOW	Fri 7/1/05	Wed 8/31/05
15	Finalize requirements & detail design	Thu 9/1/05	Fri 12/30/05
16	Install, configure and test	Mon 1/2/06	Fri 12/29/06
17	Knowledge transfer	Fri 12/1/06	Mon 4/30/07
18	**Organization and Systems Integration and Cutover**	**Tue 8/1/06**	**Fri 8/31/07**
19	Integration and testing of processes and systems	Tue 8/1/06	Wed 1/31/07
20	Data Migration	Wed 11/1/06	Wed 2/28/07
21	Cutover & Post-Cutover Support	Thu 3/1/07	Fri 8/31/07



10.5 CIS Requirements and Costs

The CIS software will be a major cost item for the CCA implementation and some initial estimates have been provided.

CIS Requirements

As mentioned above, the CIS can have wide ranging requirements and associated costs. An initial analysis, however, has been included of the range of costs for buying a CIS system that would need to be installed to operate the CCA.

The specific requirements for the CCA CIS are not clear at this stage (i.e. which areas are sitting in the "CCA" domain, which areas are sitting in the ESP domain and which areas are sitting in PG&E's domain. There may be specific need for CCA, PG&E and ESP to retain and manage identical customer information that may be changed by customer actions through each or all of the respective entities. For example:

Potentially sitting in the CCA Domain

- CRM/CIS - customer database, address data, bank details, special needs, passwords, credit scores, contact storage, customer contact interface (scripting etc.) providing customer account overview
- Change of Tenancy leading into Change of Supply/Customer Switching
- Debt Management including credit control, debt follow up rules, deposits, refunds, write-offs etc.
- Finance and Accounting
- Marketing and Sales

Probably sitting in the "Utility" domain:

- Meter reading
- Billing and bill production (mailing), accounts receivable
- Payment processing including Internet credit card, direct debit etc.
- Asset management, meter maintenance schedules, new HW installations, on-site meter works
- Distribution and operation of the network
- Security of supply (power outages)??
- Load forecasts

Probably sitting in the ESP domain:

- Load profiles and use information
- Meter data
- ISO settlement details (larger customers)
- Market price information
- Load forecasts

"Grey Areas" which may straddle one, two or all entities:

- Customer initiated work Order processing requiring utility work - suggests an interface between the City and the Utility to schedule work between customer and utility or at least communication between the utility and the CCA when a large customer is scheduled to have significant down-time.
- New Connections (form of work order processing above)
- Load profiles
- Load forecasts

CIS Costs

For the purposes of this study, we have assumed that the CCA will need a CIS with some sub-set of functionality and the associated complexities and costs. There are many providers of CIS systems and there is an equally wide range of costs. A sample of potential vendors include: Open-c Solutions, SPL WorldGroup, SAP, Kinetiq, LODESTAR, Harris Cayenta and Peace.

When considering costs it is important to include all cost items associated with the implementation including, software, hardware, consulting costs and internal IT and business costs, for design, development, start up and ongoing. In our research, one of the difficulties has been finding data that provides an "apples to apples" comparison that include all these costs.
According to TMG Consulting who specializes in CIS implementations, "For each customer service a utility can expect to spend: up to $30 for core CIS out-of-pocket vendor costs; up to $30 for core CIS utility payroll costs and expenditures; up to $30 for extended vendor services; and, up to $20 for extended CIS products. The total ranges from $50 to $110 per customer service to implement a new CIS solution. Unfortunately, the market continues to minimize installation costs. Vendors continue to push more and more installation work and responsibilities to the client side and expect to be successful."[7]

The following table shows the potential range of total costs.

Table 2: Sensitivity of CIS Costs

Customers	$/Customer	Total Cost ($)
316,000	30	9,480,000
	40	12,640,000
	50	15,800,000
	60	18,960,000
	70	22,120,000
	100	31,600,000

Another reference point is a case study based on information in the public domain, Harris Cayenta is implementing a CIS for the City of Portland's sewer, water & storm water billing to be completed in mid-2005 for $3.5 million (the equivalent of $20 per customer account). The Portland implementation is for 180,000 customer accounts. The implementation timeline for the project is 18 to 20 months. As a point of comparison, SAP's bid for the implementation was $8.8 million (the equivalent of $50 per customer account). It is not clear exactly what costs are included in these numbers (e.g. staffing costs, etc.) An electric implementation would have different complexities from this water

[7] From "A Customer System Perspective" by Greg Galluzzi, Director, UtiliPoint International, Inc. and President, TMG Consulting, Inc. on CISWorld.com

implementation and may have added rate structure complexity and may require the capability for faster future changes.

Conclusion

Since the CIS solution will likely not require full CIS functionality, it is reasonable to assume that the CIS license will be in the lower price range and the implementation will have less complexity. Based on the analysis of CCA requirements to date, the assumption can be made that a CIS could be in the range of $30 to $60 per customer account or $10 to $20 million total for implementation.

Attachment 1: Cost Worksheet

The attached cost worksheet spreadsheet is a tool to estimate ongoing CCA administration costs. The SFPUC has determined the likely job classifications and salary levels required to conduct the activities presented below.

DRAFT Cost Model for CCA Project Administration

San Francisco Salary Estimates using CCSF Civil Service Classifications

	Function	Headcount	Role	CCSF Classification	Average Salary Per Employee	Total Staff Cost
			SFPUC Overhead Rate (including COWCAP)			2.55
1	Customer Opt-Out Notification and Processing					
		1	supervisor	1480	$53,768	137,108
		3	clerks	1478	$49,023	375,026
					Function Total	**512,134**
2	Customer Care Center					
		9	customer care representatives	1478	$49,023	1,125,078
		2	supervisors	1480	$53,768	274,217
		1	manager	1478	$49,023	125,009
		1	administrative assistant	1402	$34,983	89,207
					Function Total	**1,613,510**
3	Regulatory Affairs					
		1	regulatory analyst	5601	$55,341	141,120
		1	senior regulatory analyst/manager	5634	$107,328	273,686
		0.5	administrative assistant	1402	$34,983	44,603
					Function Total	**459,409**
4	Resource Planning, Portfolio Structuring, Product & Service Development					
		2	energy analysts	5601	$55,341	282,239
		0.5	manager	5602	$81,133	103,445
		0.5	administrative assistant	1402	$34,983	44,603
					Function Total	**430,287**

5	**ESP Contract Administration and Financial Oversight**					
		3	contract, finance and reporting analysts	1823	$70,343	538,124
	*	0.5	attorney	0	$0	0
		1	manager	922	$78,013	198,933
		1	administrative assistant	1478	$34,983	89,207
					Function Total	**826,264**
6	**Sales and Marketing****					
		5	senior marketers/account representatives	931	$90,324	1,151,631
		20	account representatives for large customers	1478	$49,023	2,500,173
		1	supervisor of account representatives	1824	$82,225	209,674
	*	3	marketing specialists and outreach coordinators	5408	$0	0
	*	1	supervisor of outreach	9382	$0	0
		1	group manager	943	$136,922	349,151
		2	administrative assistants	1402	$34,983	178,413
					Function Total	**4,389,042**
7	**Bill Calculation, Presentment and Accounts Receivable Management**					
		4	billing analysts	5601	$55,341	564,478
		1	manager	5602	$81,133	206,889
					Function Total	**771,367**
					Grand Total	**9,002,014**

* City Attorney fees and communicatios functions are assumed to be covered under Overhead; marketing functions will require further study
** Does not assume a salary adjustment for adding a special condition for sales experience as this function will require

Community Choice Aggregation
Draft Implementation Plan

Appendix B:
Load Forecasting Assumptions and Processes

Prepared
By
The San Francisco Public Utilities Commission

1. INTRODUCTION

Essential to any CCA short- to long-term resource planning responsibilities is an accurate and detailed picture of the CCA customers' electricity demand. Hourly load data by customer group is required for understanding the economics of electricity procurement on a day-to-day basis. This data is also essential for forecasting medium to long-term resource needs.

The CCA will need to procure power for its customers for every hour of the day and every day of the year. The CCA will either provide this power through its own generation resources, by purchasing a variety of electricity products from the wholesale market, or a combination of both. To ensure grid reliability, CCAs and other LSEs are required to submit to the California Independent System Operator (ISO) schedules to deliver electricity that match their customers' demand with supply. The ISO uses these schedules to assess grid congestion and to balance the least costly options for avoiding bottlenecks on the power grid. Because there is the potential for additional costs associated with improper scheduling of load, an accurate understanding of electrical demand and load forecasting in both the short and long term is imperative.

LSEs are allowed to determine electrical demand for load scheduling and settlement purposes in a couple ways. The most preferential method is via interval data recording meters (or IDRs) on each and every customer site. IDRs provide, in 15-minute intervals, electric demand and energy usage. Due primarily to cost limitations only large commercial and industrial customers (with demand greater than 500 kW) are outfitted with such meters. Residential, small commercial (demand less than 20 kW), and medium commercial customers (demand between 20 kW and 500 kW) are normally equipped with simpler meters that either measure just cumulative electricity consumption or both energy and demand. These meters lack the requisite time-of-day recording necessary to understand hourly energy demand. Consequently, for any electrical load that is not interval metered, CCAs will need to utilize representative rate class load profiles as authorized by the local regulatory agency (which, in this case is the CPUC). In Phase I of the CPUC's CCA regulatory proceeding, the Commission apparently determined that CCAs should be required to schedule all non-interval-metered load using the system average rate class-specific load profiles compiled by the local Investor-Owned Utility (Pacific Gas and Electric).

2. SYSTEM AVERAGE AND CCA-SPECIFIC LOAD PROFILES

System Average Load Profiles (SALP), also known as dynamic and static load profiles[1], are intended to represent electricity usage for "typical" customers and are usually organized by customer class with data for every hour of the day and every day of the year. The purpose

[1] Dynamic load profiles (DLP) differ from static load profiles (SLP), in that DLPs are developed from load research meters and updated at a minimum weekly whereas SLPs are estimated load profiles based on historical usage. PG&E maintains DLPs for all of the rate schedules in use in San Francisco other than streetlights and agricultural rate schedules, which overall constitute negligible load.

is to track the average variation of energy usage by customer type throughout PG&E's service territory. PG&E posts their load profiles on their website and updates them on a weekly basis to account for the impact of weather conditions, which is a major driver of energy demand statewide. The load profiles, or load templates, are generated from a statistically valid sample of research meters designed to represent specific customer classes and rate schedules. Based on usage characteristics, some rate schedules are assigned their own load template while others share a template. For example, PG&E's medium commercial A10 rate schedule has its own load profile whereas the E1, E8, and E13 all share one. The numbers in the load profile represent an hourly average demand measured in kilowatts (kW) for the given sample of customers and rate classes. Because these profiles are hourly, they represent both the rate of energy consumption (kW) and the amount of energy consumed (kilowatt hours, or kWh). As PG&E explains on their website, "When you see 1.5732 on the E-1 template, you can think of 15.7 100 Watt bulbs burning for an hour. Since these are averages rather than specific customer numbers, and since real customers may turn lights on for less than an exact hour, the numbers do not come out round and we get 7/10's of a lightbulb." PG&E's system average load profiles are available for the public to view at: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml

A CCA-specific load profile would be developed similarly to the system average load profiles except that the geographical area at question is narrowed to the territory of the CCA as opposed to the entire IOU service territory. Because a CCA load profile would be limited to average usage by its customers and not customers of other geographic regions, it will capture more precisely the unique climate and demand features of the CCA. In order to produce a reliable CCA-specific load profile a statistically valid sample of load research meters must be located within city/county boundaries for all of the constituent customer classes and rate schedules. Very few, if any, cities or counties have enough such research meters installed and operating to collect the statistical data required to develop reliable city/county-specific load profiles. Because energy usage is closely correlated with weather and annual climate variance (especially driving air conditioning and space heating load), PG&E has developed load profiles with statistically valid samples by climate zone.

San Francisco is part of a coastal climate zone, climate zone T. You can think of a Climate Zone Load Profile (CLP) as representing a slice or section of PG&E's service territory. The system average load profile contains all of the climate zones in PG&E's service area. A coastal climate zone load profile shows the electrical demand of typical customers that reside within that zone. Due to our cooler summers coastal communities tend to not have the level of air conditioning demand that inland and valley communities do, making our summer demand – and the associated regional load profile – "flatter" than what is average throughout the rest of the state. PG&E does not make these load profiles available to the public on their website, however they did provide a residential and a non-residential coastal climate zone load profile to CCSF for the purposes of this draft implementation plan and cost-benefit analysis.

3. METHODOLOGY FOR DEVELOPING LOAD FORECASTS FOR CCSF's CCA

CCSF obtained monthly and annual aggregate kWh by rate schedule with numbers of customers within the political boundaries of the City and County for years 2002 and 2003 from PG&E. The SFPUC determined that the use of 2003 CCSF data alone was the best basis for the load forecast supplied to Altos Management Partners INC., for use in its economic evaluation (Chapter 4). This was due to concerns about the impact of the electric crisis in 2002 and the fact that 2003 was the first full year residential load data was divided into five tiers.[2]

PG&E divided the CCSF data into direct access (DA) and non-direct access (Non-DA) groupings. CCSF isolated only the Non-DA load and applied both system average and climate zone specific load profiles to "shape" this data into two separate streams of hourly demand that could be inserted into Altos' Contract Mix model. The Non-DA load excludes the City's municipal load, which it is assumed will continue to be served by Hetch Hetchy power, regardless of whether a CCA is formed. The load forecast provided to Altos by the SFPUC represents energy consumption at the customers' meters, and had to be "grossed up" for transmission and distribution losses (which the CCA must purchase). The Contract Mix model includes a feature to adjust for this loss percentage.

The "base case" electricity load forecast based on the 2003 data for the customers a CCA would serve was segregated into five (5) major customer classes. Due to its insignificant amount of load the SFPUC did not include street and traffic lights in its base load forecast provided to Altos. The five customer classes and their constituent rate schedules are as follows:

- Residential: E1, EL1, E7, EL7, E8, EL8 and E9A
- Small Commercial: A1, A6, A15, AG5B
- Medium Commercial: A10
- Large Commercial: E19
- Large Commercial/Industrial: E20

The Contract Mix model requires that the load forecast be in the form of a load-duration curve, which specifies the total CCA electricity demand for each of the 8760 hours per year (or for the hours during any month). To shape the data, the contract mix model can utilize either the SALP or the CLP. Using the chosen load shape, the projected total base case monthly load is spread out over all the hours of the month, in order to develop hourly electricity demand forecasts for the entire forecast horizon.

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[2] PG&E provided the SF PUC with heating and cooling degree days for 2003 as registered from the downtown San Francisco weather station in order to better understand the potential impact weather had on energy demand data that year. In general, it was warmer than normal in January 2003 (meaning less heating days) and cooler than normal in April (meaning more heating days). July 2003 was cooler than normal as well. The SF PUC did not weather normalize, or adjust for weather abnormalities, the 2003 demand data it provided to Altos Management Partners for purposes of the economic analysis of CCA.

Table 1 below shows a near term load forecast for the CCA for the period 2003-2006 using the aggregate energy consumption (MWh) by customer class.[3] To develop a load forecast for the CCA's potential customer base in 2006, CCSF utilized PG&E's system average growth rate of 1.65% as reported in its Long Term Procurement filing (R. 04-03-004) before the CPUC. Assuming that the number of customers will not vary significantly for CCSF a 0.5% growth rate was applied to the account numbers for all customer classes except Street Lighting and Traffic Controls.

Table 1: Near-Term CCSF CCA Load Forecast 2003-2006[4]

CCSF CCA Load Forecast*

Sector	2003 MWh	2003 Accounts**	2004 MWh	2004 Accounts**
Residential	1,436,144.88	321,558	1,459,841	323,166
Small Commercial	517,401	27,935	525,939	28,074
Medium Commercial	720,311	3,473	732,196	3,490
Large Commercial	559,231	751	568,458	755
Large C/I	829,050	93	842,729	93
Total	4,062,138	353,810	4,129,163	355,579

Sector	2005 MWh	2005 Accounts**	2006 MWh	2006 Accounts**
Residential	1,483,929	324,782	1,508,413	326,406
Small Commercial	534,616	28,215	543,438	28,356
Medium Commercial	744,277	3,508	756,558	3,525
Large Commercial	577,838	759	587,372	762
Large C/I	856,634	94	870,769	94
Total	4,197,295	357,357	4,266,550	359,144

[3] Due to its minimal contribution to overall load, street and traffic light information was not included in the load forecast.

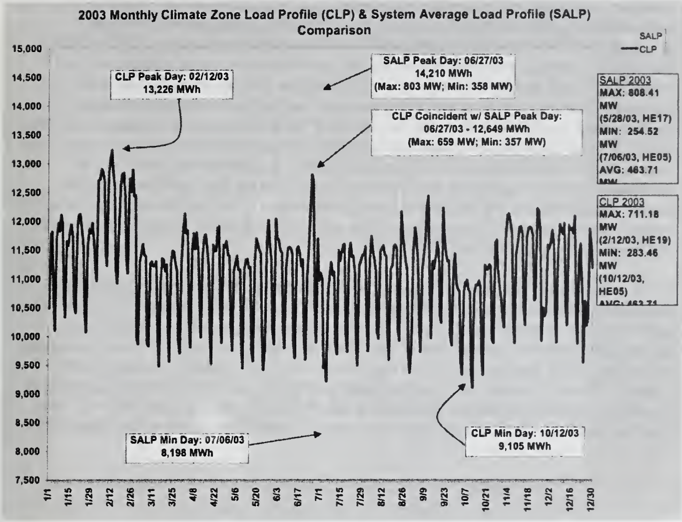
[4] 2003 Load data provided by PG&E. Applied PG&E's projected system average growth rate of 1.65% as stated in their long-term procurement plan to subsequent years. Because account numbers will grow at a rate less than energy consumption, CCSF used a 0.5% growth rate for account numbers.
Medium Commercial, Large Commercial, and Large C/I account data was provided incomplete by PG&E due to application of the "15-15" Rule. CCSF estimated the total number of accounts for rate classes that were not provided by using PG&E's FERC Form 1 "KWh of Sales Per Customer" for these rate classes and dividing that figure into annual KWh totals for the associate rate classes for CCSF. CCSF is awaiting an update from PG&E pursuant to CPUC Decision 04-12-046.

4. COMPARISON OF SYSTEM AVERAGE[5] AND CLIMATE ZONE[6] LOAD PROFILING

In the chart below we compare 2003 CCA load data shaped separately by the System Average Load Profile (SALP also called DLP in Chapter 4) and Climate Zone Load Profile (CLP also called CZP in Chapter 4) to show their different impact on the overall shape of San Francisco's hourly electrical demand over the course of a year or 8760 hours. As discussed above, load profiles are developed to represent the prototypical energy use of a group of customers. The CLP models energy demand characteristics of typical coastal climate zone customers. The SALP is designed to represent the prototypical energy use of PG&E's average customers across all the climate zones in their service territory. In order to examine the impact of the SALP and CLP on San Francisco's energy demand we graphed the sum of hourly demand to get daily totals. Each data point represents the total amount of energy that would need to be procured in each day of the year from January 1st to December 31st (in thousands of MWhs per day).

[5] PG&E's system average load profiles, also known as dynamic and static load profiles, are posted on their website at: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml. PG&E's load profiles are provided by rate schedule. None of the dynamic load profiles for April 6, 2003 had data for hour 3. Instead the same hour one week earlier was used in its place. In all cases the dynamic load profile was used when available. A static load profile was used for agricultural rate schedule data because PG&E does not provide a dynamic load profile for such customers. To calculate the hourly load shapes the SF PUC used the following formula: Sum of MWh (by rate schedule by month, for example, the sum of energy use for all San Franciscan E1 customers for January would be calculated separately from consumption in February) x Load Profile for a Specific Hour / Monthly Normalization Factor (sum of same month's hourly load profile stream) = Energy Use for Customer Receiving Service under that Rate Schedule for a Specified Hour. The SALP was imposed on a monthly basis (as opposed to an annual basis) to develop a load shape that more accurately captures the seasonal usage variations of San Francisco customers. This data was provided to Altos for insertion into their Contract Mix model by customer class groupings (Residential, Small Commercial, Medium Commercial, etc.) as described above.

[6] Whereas the SALPs (dynamic and static load profiles) were imposed on San Francisco's monthly MWh consumption totals by rate schedule, PG&E provided the SF PUC with coastal climate zone specific load profiles broken into only two groups: residential and non-residential. Consequently, instead of imposing rate schedule specific load profiles on rate schedule specific energy use totals, rate schedule energy data was grouped into broader categories such as residential, small commercial, medium commercial, large commercial, and large commercial/industrial prior to imposing the climate zone load profile. The same general formula that was used in calculating the SALP load shape was used in developing the CLP load shape.



As expected, PG&E's SALP (in yellow) is "peakier" in the summer than the CLP (in blue). This is primarily due to more inland air conditioning load during system peak periods than used in coastal zones. This indicates that using the SALP to determine hourly energy demand would require the CCA to procure more peak power during the summer than if the CLP was used. Conversely, the CLP is generally flatter than the SALP, meaning it shows less of a difference between its daily peak and its base demands. What is more surprising, however, is the discrepancy between the SALP and CLP coincident peaks. The SALP peaks on June 27 with 808 MW of demand while on the same day the CLP peaks at 659 MW, a difference of 149 MW, or 18 percent. There is also a significant difference between the two shapes' non-coincident peaks. Again, the SALP peaks in June with 808 MW and the CLP peaks in February with 711 MW, a difference of 97 MW. Beside the fact that one profile may portray San Francisco's actual energy usage characteristics more accurately than the other, the financial impact of these differences may be significant for the CCA. A flatter load profile as shown by the CLP means in theory that the CCA can purchase larger blocks of inexpensive "baseload" power, also known as 7 x 24 power (seven days of the week, 24 hours per day). However the SALP also demonstrates lower minimum purchase requirements, particularly during summer months – it may be that wholesale purchasing and settlement related to the SALP may prove less expensive during those months.

However, it is important to note that when and if a CCA is formed in San Francisco, the CCA will schedule load for its largest commercial and industrial customers with forecasts developed from interval-metered data, and not with load-profiled forecasts. This will dilute the impact of using a potentially inaccurate load profile for developing forecasts for load scheduling. Load profiles of some sort will still need be used for scheduling all load that is not interval-metered including residential and small and medium commercial demand. To the extent that the CCA is required to use the SALP for scheduling all non-interval-metered load, it is more likely that the difference between SALP projected peak loads and actual peak loads will have the largest negative impact financially. In other words, if the CCA is purchasing excess power during peak periods, it will be taking more than it needs of the highest cost power and will be forced to recoup those costs by selling the excess on the spot market. At the very least, increasing such transactions during peak periods will increase the risk of monetary losses for the CCA.

SALP-inflated peak power projections and purchases may be exacerbated by resource adequacy rules currently being developed by the CPUC. If the CCA is required to purchase reserves and extra capacity during peak summer months based on inflated summer peak power projections the financial cost of SALP load forecasts may increase. In some instances a "peakier" CCSF load profile (SALP) may temper the CCA's resource adequacy costs.[7] Until the resource adequacy rules are finalized, their impact on CCA costs and load profiling procedures will remain unclear. However, in theory the use of the "spikier" SALP for load forecasts and load scheduling should be more costly to the CCA than use of the flatter CLP.

[7] Such as if all hours of load during "peak" summer months within a certain percentage of the CCA's summer peak must be forward contracted or have extra capacity.

Community Choice Aggregation
Draft Implementation Plan

Appendix C:
Examples of Requests for Proposals (RFPs)
From Other Jurisdictions

Request for Proposals
Northeast Ohio Public Energy Council

Electric Power Supply
For
Participating Consumers
in Member Communities

NORTHEAST OHIO PUBLIC ENERGY COUNCIL
c/o City of Eastlake
35150 Lakeshore Boulevard
Eastlake, Ohio
44095

Request for Proposals
Northeast Ohio Public Energy Council

Electric Power Supply
For
Participating Consumers in Member Communities

INDEX

Advertisement for Proposals

Northeast Ohio Public Energy Council

NOTICE IS HEREBY GIVEN by the Northeast Ohio Public Energy Council, a regional council of governments established under Ohio law, that Sealed Proposals will be received by the Northeast Ohio Public Energy Council ("NOPEC") for:

Electric Power Supply
For
Participating Consumers in Member Communities

Proposals shall be received at the office of the Mayor, City of Eastlake; 35150 Lakeshore Boulevard; Eastlake, Ohio; 44095 until 4:00 p.m. local time on **December 29, 2000**.

Specific Conditions and a description of the Proposals requested (Proposal Packet) are available and may be obtained at the above office of NOPEC during regular business hours of 8:30 a.m. to 4:30 p.m.

Parties interested in submitting a proposal will be required to provide a non-refundable certified check for $1,000.00 payable to the Northeast Ohio Public Energy Council to receive an Appendix Packet containing required proposal forms, customer and load data and a form of contract related to the provision of firm all-requirements retail electric supply for participating consumers in NOPEC member communities. Proposals must be submitted on the forms provided.

NEITHER NOPEC NOR ANY MEMBER COMMUNITIES SHALL HAVE ANY LIABILITY FOR EXPENDITURE PURSUANT TO THIS ADVERTISEMENT FOR PROPOSALS OR ANY CONTRACT ENTERED INTO IN CONNECTION HEREWITH. NOPEC RESERVES THE RIGHT TO CANCEL THE SOLICITATION, REJECT ANY AND ALL PROPOSALS, TO WAIVE ANY TECHNICALITIES, TO REQUEST ADDITIONAL PROPOSALS OR INFORMATION, AND TO OTHERWISE PROCEED IN ACCORDANCE WITH THE BEST INTERESTS OF NOPEC AND ANY MEMBER THEREOF.

Parties offering proposals shall provide NOPEC with an original and twelve (12) copies of said proposal. Under no circumstances will NOPEC be responsible for any costs incurred by any party responding to this Request for Proposals.

The successful party will be required to enter into a contract with NOPEC or its designee based upon the materials submitted and any mutually agreeable negotiations completed between the parties.

Northeast Ohio Public Energy Council
c/o City of Eastlake

Request for Proposals
Instructions

Northeast Ohio Public Energy Council
c/o City of Eastlake
35150 Lakeshore Boulevard
Eastlake, Ohio 44095

Electric Power Supply
For
Participating Consumers in Member Communities

General Conditions

1.1 Description

The services to be proposed consist of firm all-requirements retail electric power supply to participating consumers in member communities of the Northeast Public Energy Council ('NOPEC").

1.2 Time and Place for Receipt of Proposal

Written Proposals will be received by NOPEC, clearly marked as noted in section 1.10, for the above services at its office located at City of Eastlake, 35150 Lakeshore Boulevard, Eastlake, Ohio, 44095 until 4:00 p.m. local time on **December 29, 2000**.

1.3 Compliance with Conditions

The proposal must be based on the General Conditions and Specific Conditions contained in this Proposal Packet, as well as the required form, sample contract, and customer and load data provided in an Appendix Packet. Except as provided in the instructions contained herein, proposers are not to contact, either directly, or indirectly, members of the Board of NOPEC, the staff of NOPEC, member communities, advisors, or any person who might influence the decision-making process related to this request, for the period of **November 30, 2000**, to the date of contract award, if any award is made. All proposals must be delivered in written hard copy form required by the submission deadline. No facsimile or other electronic submissions shall be accepted.

Should errors or omissions be found in the General Conditions, Specific Conditions, or information contained in the Appendix Packet, NOPEC should be informed at once, and NOPEC will immediately notify each person who has obtained an Appendix Packet, or who has submitted a fee with the intent to receive an Appendix Packet, of the needed correction.

1.4 Proposal Submission Fee

Parties desiring to submit a power supply proposal must provide a non-refundable certified check for $1,000.00 payable to the Northeast Ohio Public Energy Council at the address set forth in section 1.2 to receive necessary forms, data, and information contained in the Appendix Packet.

1.5 Additional Information

Questions and requests regarding this RFP must be submitted in writing. Written responses to all questions will be provided to all parties who have submitted the proposal submission fee as specified in section 1.4. No telephone, facsimile, or e-mail inquiries will be acknowledged. Additional information requests are due by 4:00 p.m. on **December 8, 2000** at the address set forth in section 1.2.

1.6 Decision Criteria

All proposals will be evaluated by the NOPEC Board of Directors and its advisors utilizing the following criteria:

a) Qualifications, reputation, and experience of supplier;
b) Timing of service to all participating customers in member communities;
c) Bid prices;
d) Portfolio of power supply offered, including renewable energy;
e) Proof of firmness of transmission agreements;
f) Proof of firmness and reliability of generation capacity;
g) Ability to provide financial surety or guarantee such as a letter of credit, corporate guarantee, performance bond, escrow fund, or other form of guarantee;
h) Capability to manage and service a large customer base, and;
i) Ability to provide a program administration fee to NOPEC.

1.7 Proposal Execution and Treatment

All power supply proposals shall be considered an offer to provide firm all-requirements retail electric supply to participating consumers. Proposals shall be executed by a person who has the authority to legally bind the proposer. A corporate resolution or other authorization necessary to legally bind the proposer shall be submitted with the proposal. All proposals shall be treated with confidentiality to the extent allowed by Ohio law throughout the review and selection process.

1.8 Period of Validity

All proposals will be deemed valid until **January 31, 2001**, or through the end of the supplier selection and approval process, whichever is later.

1.9 Interview

Each proposer must be available for an interview at NOPEC's offices upon notification by NOPEC.

1.10 Form of Proposal

Proposals shall be in hard copy typewritten form. Proposals may not be submitted by facsimile or other electronic transmission. Each proposer must submit one original and twelve (12) copies of their proposal, along with twelve (12) copies of any supporting documentation. Proposals must be submitted on the form provided in section A of the Appendix Packet. All corrections or erasures shall be initialed by the person signing the proposal. Envelopes containing the Proposal shall be plainly marked:

Electric Power Supply
For
Participating Consumers in Member Communities

1.11 Right to Accept or Reject

In connection to this Request for Proposals, NOPEC reserves the right to:

a) Cancel this solicitation;
b) Reject any or all Proposals;
c) Issue additional instructions or extend the submission deadline;
d) Request an oral interview with, or request additional information from, individuals or firms prior to final award of contract;
e) Select any firm or combination of firms for contract negotiations which, in NOPEC's judgment, will best meet NOPEC's needs, regardless of any differences in estimated prices or conditions between the firm's and others' proposals;
f) Negotiate a contract that covers selected parts of a Proposal or applies other specific conditions mutually agreed upon;
g) Change any proposed schedule for the program or cancel any proposed program without any financial obligation for services provided, out-of- pocket expenses incurred, or any other obligations of the proposer;
h) Waive any technicalities and make any award(s) determined to be in NOPEC's best interests.

1.12 Non-Discrimination

NOPEC is an Equal Opportunity Employer and therefore encourages minority and female business enterprise participation in this process (i.e. either as a proposer or in a partnership capacity). It is the policy of NOPEC that all proposers shall provide a copy of their Affirmative Action Program upon request.

Specific Conditions

2.0 NOPEC AND PROGRAM INFORMATION

2.1 NOPEC Profile

The Northeast Ohio Public Energy Council ("NOPEC") is a regional council of governments established under Chapter 167 of the Ohio Revised Code. It is comprised of approximately 104 municipalities, counties, and townships located within eight counties in Northeast Ohio. NOPEC was formed to act as purchasing agent for participating electric consumers in member communities. The communities which have formally joined NOPEC to date include 25 communities located in the Ohio Edison service territory and 64 communities located in the Cleveland Electric Illuminating Company service territory. These member communities have engaged in a required public process in which each municipality, township or county has: 1) adopted a resolution to join NOPEC, and; 2) obtained approval from the voters in such community authorizing the establishment of an opt-out aggregation program.

The 64 member communities in the Cleveland Electric Illuminating Company (CEI) service territory include a potential base of 308,071 customers who consumed an estimated 4.9 million megawatt hours during the 12 months ending October 2000. The 25 member communities in the Ohio Edison Company (OE) service territory include a potential base of 99,857 customers who consumed an estimated 2.1 million megawatt hours during the 12 months ending October 2000. Information on the load of the aggregated communities broken out by utility service territory and customer class is contained in section B of the Appendix Packet. Member communities to date are included in the first data group included in section B of the Appendix Packet. A second data group for communities that are not yet formal members is anticipated to be released within 60 days under this same Request for Proposals as section D of the Appendix Packet.

2.2 Proposal Flexibility

NOPEC seeks proposals for firm all-requirements retail electric supply for participating customers for a period of up to fifty-eight months commencing on or about **March 1, 2001** and ending **December 31, 2005**, or another period offered by the proposer.

Proposers may submit pricing schedules to provide power supply: a) to participating customers in both the CEI and OE service territories; b) only to participating customers in the CEI service territory, or; c) only to participating customers in the OE service territory.

If a proposal is offered for both service territories, a separate pricing schedule sheet for each company service territory must be included in the proposal.

NOPEC seeks pricing and terms of service for each class of shoppable customers. As noted in section 4.1 and as described in the information on pricing contained in section B of the Appendix Packet, latitude is allowed for developing individualized pricing for industrial and commercial accounts in recognition of their varied range of load factors and other characteristics.

2.3 Selection of Power Supplier

The selection process shall take place in two stages. In the first stage, a "short list" of prospective suppliers will be chosen based upon the proposals received. In the second stage, contract negotiations with suppliers on the "short list" will take place to determine the most advantageous proposal or proposals, taking into consideration the pricing schedule and other factors outlined in section 1.6. While pricing is requested for all classes of customers in each proposal, final selection may include multiple suppliers which would serve only selected classes of customers.

2.4 Notification of Customers

Prior to commencement of service, each prospective customer in each member community will be notified via U.S. mail of the contract pricing and their individual option to "opt-out" of the aggregated group and choose another supplier, or regulated service from First Energy. The selected supplier(s) shall receive an electronic list of all prospective customers in the aggregated group, including name and mailing address. NOPEC shall develop the text of the "opt-out" notice to be mailed, but all costs associated with preparation of the mailing lists, printing and mailing of this notice, and administration for the customers responding shall be the responsibility of the selected supplier(s).

2.5 Adjustment of Participating Customer Service List and Customer Enrollment

Based upon responses to the "opt-out" mailing, the selected supplier(s) shall bear responsibility and all costs associated with deleting each customer who confirms in writing the choice to "opt-out" from the prospective customer list. The resulting Customer Service List shall be transmitted in required batch amounts electronically to First Energy for enrollment of customers. The selected supplier(s) must assume all costs related to "opt-out" adjustments and customer enrollment including a $5.00 per customer initial switching fee, unless such fee is eliminated or reduced by First Energy.

2.6 Market Support Generation Claims

The selected supplier(s) shall be responsible for making and perfecting claims for Market Support Generation and Non-Market Support Generation, as such terms are defined by First Energy Corp. in its protocols.

2.7 Customer Service

Customer service by the selected supplier(s) shall be carried out in strict compliance with the rules and regulations of the Public Utilities Commission of Ohio as may be promulgated from time to time and consistent with the terms of the Supply Contract and the Plan of Operation and Governance adopted by each NOPEC member community.

2.8 Contract Administration

General administration of the RFP, the contracting process, and certain on-going monitoring and management activities related to the aggregation program for power supply shall be carried out by NOPEC, or a designee of the NOPEC. The selected supplier(s) shall provide an administrative fee to be specified in the contract.

3.0 BUSINESS INFORMATION REQUIREMENTS

3.1 Contact(s)

Name and business address of the principal officer responsible for submission of the RFP and (if different) name and principal officer responsible for administration of the contract.

3.2 Business Information

Legal trade name; date of incorporation or organization; state of incorporation or organization; list of officers and directors; list of affiliates, if any; a copy of 1998 and 1999 Annual Reports to Stockholders, or other audited annual report; copies of final year-end FERC Form 1 filings for 1998 and 1999; current bond rating(s) by Moody's Investor Services, or other rating agencies, if applicable; latest audited financial statement(s) with confirmation of no material or adverse changes since the date of statement(s).

3.3 Business Qualification

Membership in regional power pools, or agreement with a member of a regional power pool; Certification of all regulatory approvals necessary to provide all-requirements, firm power included in offer; Certificate of Good Standing from the Ohio Department of Taxation, or similar certification that all state taxes have been paid in state of incorporation or organization; Evidence of qualification to do business in Ohio; a copy of Certification as a power supplier in the state of Ohio and related filing materials for certification, or date planning to be certified.

3.4 Business Status

Statement as to whether or not the business or affiliate has commenced, or been forced into, any insolvency proceeding within the last five years; statement as to whether business or affiliate has been subject to any investigation by a state or federal agency within the last five years; statement as to the number, if any, of consumer complaints filed with a state, federal, or local agency, against the business or affiliate within the last five years.

3.5 Business Relationships

Identification of any affiliate or co-venturer, engaged in service delivery in the state of Ohio, such as a wholesale power supplier, service vendor, or other energy or wires related services; and relationship to such party.

4.0 PRICING REQUIREMENTS

4.1 Pricing Schedules and Format

As noted in section 2.2, NOPEC is seeking proposals for firm all-requirements retail electric supply for participating customers in member communities for a period of up to 58 months commencing on or about **March 1, 2001** and ending **December 31, 2005**, or another period offered by the proposer. Pricing is sought for each class of customers, with recognition that individual pricing may be needed for industrial and commercial accounts with a varied range of load factors and other characteristics. A list of the shoppable customer classes and load and customer information for each utility service territory is contained in section B of the Appendix Packet. Instructions and a format for pricing are also contained in section B of the Appendix Packet.

NOPEC is seeking delivered energy prices at a discount below the comparable. Standard Offer Prices for customers in the CEI and OE service territories. Prices must be expressed as cents per kilowatt hour for each customer class to be served. As indicated in the format for pricing, the comparison of bid price and Standard Offer price must be clearly delineated for each year of supply proposed.

Proposers may submit pricing schedules to provide power supply: a) to participating customers in both the CEI and OE service territories; b) only to participating customers in the CEI service territory, or; c) only to participating customers in the OE service territory.

If a proposal is offered for both service territories, a separate pricing schedule sheet for each company service territory must be included in the proposal.

4.2 Market Support Generation Scenarios

For each service territory for which a bid is submitted (CEI or OE), suppliers must provide pricing in five scenarios related to the assumed availability or lack of availability of Market Support Generation and Non-Market Support Generation, as those terms are defined by First Energy Corp. protocols. Scenario A will include 75% of Market Support Generation and 75% of Non-Market Support Generation available for the customer class from OE or CEI; Scenario B will include 50% of Market Support Generation and 50% of Non-market Support Generation available for the customer class from OE or CEI; Scenario C will include 25% of Market Support and 25% of Non-Market Support Generation available for the customer class from OE or CEI; Scenario D will include 10% of Market Support Generation and 10% of Non-Market Support Generation available for the customer class from OE or CEI. Scenario E will include 0% of Market Support Generation and 0% of Non-Market Support Generation. In addition to these (five) required scenarios, suppliers may also propose additional pricing scenarios related to assumed levels of Market Support and Non-Market Support Generation that may be practically attained. (See instructions and pricing forms in section B of the Appendix Packet.)

4.3 Flat Annual or Seasonal Pricing

For each service territory for which a bid is submitted, suppliers may provide a single or multiple pricing proposals, (i.e. summer/winter, or flat annual pricing).

4.4 Pricing Change Factors

Proposers must clearly state their bid prices and any factors which would require changes in the prices based on inflation indexes, fuel/power cost adjustments, changes in shopping credit levels, etc. Any index must be clearly identified. Bidders must also indicate if changes in price would be required at various levels of total power supply to be provided (i.e. 4 million MWh, 2 million MWh, 1 million MWh).

4.5 Inclusion of All Supplier Costs in Pricing

Prices must include all supplier costs for firm all-requirements power supply, transmission, and all associated administrative and any additional charges related to proposed service to the consumer.

4.6 Phase-In of Service Initiation

Prices must be offered to all classes of customers, but suppliers may propose to phase-in classes of customers on a firm schedule to manage or ramp-up service initiation.

4.7 New Customers and New Member Communities

Proposers must certify their willingness to provide service to new customers in

member communities at existing contract prices, and willingness for new member communities to join in the contract at prices to be set under then current market conditions.

4.8 Other Conditions

While the form of pricing and scenarios must be provided as noted above and in section B of the Appendix Packet, proposers may also offer other conditions or terms for supply at prices below Standard Offer for each class of customers.

5.0 POWER SUPPLY PORTFOLIO AND RELIABILITY

5.1 Portfolio Profile

Through information on the portfolio profile, NOPEC seeks to assess experience, total power supply capabilities and the supply being offered. Data is requested on: total supply capabilities; amount of power the proposer provided at to retail customers, and the number of existing retail customers supplied in 1998 and 1999, and the first six months of 2000; name and location of facilities to be used to provide power supply under this proposal, including: fuel type, capacity, year originally placed in service, and current availability status; percent of renewable energy in power supply mix under this proposal, and; specification of any emission credits related to power supply included in the proposal.

5.2 Transmission and Reliability

Proposers are requested to provide information on transmission and reliability to evaluate factors affecting reliability of the proposed supply including: priority of supply during "tight capacity" conditions including forced outages, curtailment, peak load periods, or other situations in which capacity is restricted in any manner; range of ancillary services related to reserves; contracts and agreements for transmission; options for new or expanded load, and; nature of any other guarantees. Documentation should indicate firm annual network transmission equivalent in priority to native load.

6.0 NON-PRICE FACTORS

6.1 Compliance with Billing and Collection Requirements

Proposers must certify their willingness to abide by billing, collection and termination regulations of specified in Public Utilities Commission of Ohio approved tariffs and approved provisions of market and electronic business transactions, and any additional protections set forth by the Public Utilities Commission, Ohio law, or those provisions deemed mandatory in the form of contract contained in Appendix C.

6.2 Non-Discrimination

Proposers must also certify their willingness to serve all eligible aggregated customers, regardless of income, without requesting a deposit, guarantee, or other security beyond that permitted by the Public Utilities Commission of Ohio and the form of contract contained in Appendix C. Restoration of supply will not be required for customers terminated in accordance with Public Utilities Commission of Ohio procedures.

7.0 APPENDIX PACKET

As noted in section 1.4, parties desiring to submit a proposal must provide a non-refundable certified check for $1,000.00 payable to the Northeast Ohio Public Energy Council at the address set forth in section 1.2 to receive necessary forms, data, and information contained in the Appendix Packet.

8.0 NOTIFICATION OF AWARD

Any contract resulting from this RFP shall be deemed as having been awarded when formal written notice of acceptance of the proposal has been duly served upon the successful Bidder.

2004 PILOT ELECTRIC SUPPLY AGREEMENT

WHEREAS, the Massachusetts Legislature has adopted Chapter 164 of the Acts of 1997, (the "Restructuring Act"), which, *inter alia,* (1) allows for competition in the generation and supply of electricity to customers, (2) authorizes municipalities to aggregate the electrical load of electricity consumers within their boundaries, and (3) allows municipal aggregators to formulate an aggregation plan and conduct aggregation programs;

WHEREAS, several municipalities in Barnstable County and Dukes County ("Member Municipalities") have formed the Cape Light Compact ("Compact") and entered into an "Inter-Governmental Agreement of the Cape Light Compact" ("Compact Agreement"), for the purposes, *inter alia*, of acting as a municipal aggregator and negotiating the best rates for the supply of electricity to consumers located on Cape Cod and Martha's Vineyard;

WHEREAS, all twenty-one Barnstable County and Dukes County towns presently belong to the Compact;

WHEREAS, the Compact has developed a Default Service Pilot Project (the "Pilot Project") to aggregate consumers located within the Member Municipalities presently receiving Default Service and to negotiate competitive rates for the supply of electricity for such consumers;

WHEREAS, the Massachusetts Department of Telecommunications and Energy ("DTE") approved the Pilot Project by a letter dated October 23, 2001, as well as in the November 20, 2001 Order on Motion for Reconsideration, both in DTE 01-63;

WHEREAS, the DTE also approved the Pilot Electric Supply Agreement dated March 13, 2002 between the Compact and Mirant Americas Retail Energy Marketing, LP ("Supplier") pursuant to which Supplier agreed to sell All-Requirements Power Supply to Default Service customers pursuant to the Pilot Project through December 31, 2003; and

WHEREAS, the Compact and Supplier desire to enter into a new Pilot Electric Supply Agreement on substantially the same terms and conditions for calendar year 2004.

NOW THEREFORE, IT IS AGREED THAT, the Compact and the Supplier hereby enter into this Pilot Electric Supply Agreement ("Agreement") subject to the terms and conditions below.

ARTICLE 1 DEFINITIONS When used in this Agreement, the following terms shall have the meanings given, unless a different meaning is expressed or clearly indicated by the context. Words defined in this Article 1 which are capitalized shall be given their common and ordinary meanings when they appear without capitalization in the text. Words not defined herein shall be given their common and ordinary meaning.

1.1 **Aggregation Plan** - The "Cape Light Compact Aggregation Plan" as adopted or amended by the Compact, from time to time, and as approved by the DTE on August 10, 2000 in DTE 00-47. The Aggregation Plan is a plan developed by the Compact to aggregate electric consumers for the primary purpose of negotiating the best rates for the supply and distribution of electricity for such consumers.

1.2 **Aggregation Program** - The Community Choice Power Supply Program is one of the two programs described in, and implemented under, the Aggregation Plan.

1.3 **Agreement** - This Pilot Electric Supply Agreement.

1.4 **All-Requirements Power Supply** - Service under which the Supplier provides all of the electrical energy, capacity, reserves, and ancillary services for firm power supply to Participating Consumers at the Point of Sale.

1.5 **Bankruptcy** means with respect to a Party that such Party (i) ceases doing business as a going concern, generally does not pay its debts as they become due or admits in writing its inability to pay its debts as they become due, files a voluntary petition in bankruptcy or is adjudicated bankrupt or insolvent, or files any petition or answer seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other present or future applicable federal, state or other Governmental Rule, or seeks or consents to or acquiesces in the appointment of any trustee, receiver, custodian or liquidator of said Party or of all or any substantial part of its properties, or makes an assignment for the benefit of creditors, or said Party takes any corporate action to authorize or that is in contemplation of the actions set forth in this clause (i); or (ii) a proceeding is initiated against the Party seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other Governmental Rule and, such proceeding is not dismissed within ninety (90) days after the commencement, or any trustee, receiver, custodian or liquidator of said Party or of all or any substantial part of its properties is appointed without the consent or acquiescence of said Party, and such appointment is not vacated or stayed on appeal or otherwise within ninety (90) days after the appointment, or, within ninety (90) days after the expiration of any such stay, has not been vacated, *provided that*, notwithstanding the foregoing, the exercise of rights to take over operation of a Party's assets, or to foreclose on any of a Party's assets, by a secured creditor of such Party (including the appointment of a receiver or other representative in connection with the exercise of such rights) shall not constitute a Bankruptcy.

1.6 **Commercially Reasonable** - Any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known, or which in the exercise of due diligence, should have been known, at the time the decision was made, would have been expected in the industry to accomplish the desired result consistent with reliability, safety, expedition, project economics and applicable law and regulations.

1.7 **Compact** - The Cape Light Compact, formed in October 1997, by an intergovernmental agreement under the Massachusetts General Laws and presently consisting of twenty-one (21) towns in Barnstable and Duke Counties and the two counties themselves for which the Compact acts as agent.

1.8 **Compact Agreement** - The Inter-Governmental Agreement of the Cape Light Compact, as in effect on July 31, 1998 and as may be amended from time to time.

1.9 **Counties** - Barnstable County and the County of Dukes County. In the singular, County shall refer to either of the two Counties.

1.10 **Default Service** - As defined in G.L. c. 164, §1 and in orders of the Massachusetts Department of Telecommunications and Energy, as amended or promulgated, as the case may be, from time to time.

1.11 **Distribution Company** - The Commonwealth Electric Company, or any successor company(ies) or entity(ies) providing electricity distribution services in each Member Municipality.

1.12 **DTE** - The Massachusetts Department of Telecommunications and Energy, or any successor state agency.

1.13 **Eligible Consumer** - A residential, commercial, industrial, municipal, or other consumer of electricity who is receiving Default Service from the Distribution Company as of the Effective Date of this Agreement or any consumer who physically relocates into a Member Municipality and would be automatically enrolled to receive electric supply service under the Distribution's Company Default Service tariff. All Eligible Consumers must reside or be otherwise located at one or more locations within the geographic boundaries of a Member Municipality, as such boundaries exist on the Effective Date of this Agreement. Eligible Consumers shall not include those consumers who are on Standard Offer Service ("SOS") as of the Effective Date of this Agreement or thereafter. Additionally, consumers who may be temporarily switched to Default Service from SOS or switched to Default Service from competitive supply shall not be considered Eligible Consumers.

1.14 **Effective Date** - The effective date of this Agreement, pursuant to Article 4.2 below.

1.15 ***Force Majeure*** - Any cause not within the reasonable control of the affected Party which precludes that party from carrying out, in whole or in part, its obligations under this Agreement, including, but not limited to, Acts of God; winds; hurricanes; tornadoes; fires; epidemics; landslides; earthquakes; floods; other natural catastrophes; strikes; lock-outs or other industrial disturbances; acts of public enemies; acts, failures to act or orders of any kind of any governmental authorities acting in their regulatory or judicial capacity, provided, however, that any such discretionary acts, failures to act or orders of any kind by the Compact or a Member Municipality may not be asserted as an event of *Force Majeure* by the Compact or a Member Municipality as the case may be; insurrections; military action; war, whether or not it is declared; sabotage; riots; civil disturbances or explosions. Nothing in this provision is intended to excuse any Party from performing due to any governmental act, failure to act, or order, where it was reasonably within such Party's power to prevent such act, failure to act, or order. Economic hardship of either Party shall not constitute an event of *Force Majeure*.

1.16 **Governmental Authority** - Any national, state or local government, independent system operator, regional transmission owner or operator, any political subdivision thereof or any other governmental, judicial, regulatory, public or statutory instrumentality, authority, body, agency, department, bureau, or entity, excluding the Compact and all Member Municipalities.

1.17 **Governmental Rule** - Any law, rule, regulation, ordinance, order, code, permit, interpretation, judgment, decree, or similar form of decision of any Governmental Authority having the effect and force of law.

1.18 **ISO** - The New England Independent System Operator, or such successor or other entity which oversees the integrated dispatch of power plants in New England and the bulk transmission of electricity throughout the New England power grid.

1.19 **kWh, kW** - Kilowatt-hour and kilowatts, respectively.

1.20 **Member Municipalities** - The twenty-one (21) towns and two (2) Counties which are presently members of the Cape Light Compact as of the Effective Date of this Agreement. The Member Municipalities include the following towns in Barnstable County: Barnstable, Bourne, Brewster, Chatham, Dennis, Eastham, Falmouth, Harwich, Mashpee, Orleans, Provincetown, Sandwich, Truro, Wellfleet and Yarmouth, and the following towns in Dukes County: Aquinnah, Chilmark, Edgartown, Oak Bluffs, Tisbury and West Tisbury. The Compact acts as agent for the Member Municipalities as set forth in Article 2.2 below.

1.21 **Participating Consumer** - All Eligible Consumers, excluding those Eligible Consumers who exercise their ability to opt-out, whether prior to the automatic enrollment or anytime thereafter. A Participating Consumer who chooses to opt-out of the Pilot Project at any time is ineligible to become a Participating Consumer for one year.

1.22 **Parties** - The Compact and Supplier, as the context requires. In the singular, "Party" shall refer to any one of the preceding.

1.23 **Pilot Project** - The Default Service Pilot Project is a municipal aggregation program developed by the Compact pursuant to its Aggregation Plan and Aggregation Program to provide choice and savings for Eligible Customers through competitive supply. The DTE approved the non-price terms of the Pilot Project, as included in the Compact's August 15, 2001 filing, on October 23, 2001 in DTE 01-63 and on November 20, 2001 in DTE 01-63A (reconsideration).

1.24 **Point of Delivery** - The point of interconnection between NEPOOL Pool Transmission Facilities ("PTF") and the transmission facilities of the Distribution Company.

1.25 **Point of Sale** - The electric meter for each Participating Consumer's account, as designated by the Distribution Company.

1.26 **Restructuring Act** - Chapter 164 of the Massachusetts Acts of 1997.

1.27 **Supplier** – Mirant Americas Retail Energy Marketing, LP, a Delaware limited partnership, duly authorized to conduct business in the Commonwealth of Massachusetts.

ARTICLE 2 RIGHTS GRANTED

2.1 **General Description and Limitations** - The Supplier is hereby granted the exclusive right to provide All-Requirements Power Supply to Participating Consumers pursuant to the terms of the Compact's Pilot Project, expressly conditioned on the terms and conditions set forth in this Agreement. In accepting this grant, the Parties recognize that the Supplier is only authorized to supply All-Requirements Power Supply to Participating Consumers, and that the Distribution Company will continue to have the right and obligation to supply electricity to all Eligible Consumers or Participating Consumers who opt-out of the Pilot Project and remain on, or return to, Default Service, until changes in law, regulation or policy may allow otherwise. The Supplier further recognizes that this Agreement does not guarantee that any individual Eligible Consumer will be served by the Supplier. All existing and any new Eligible Consumers shall be automatically enrolled in the Pilot Project, unless they choose to opt-out. In the event the geographic boundaries of a Member Municipality change during the term of this Agreement, Supplier shall only be obligated to supply All-Requirements Service to those Participating Consumers located within such Member Municipality as such boundaries existed on the Effective Date of this Agreement. As between the Parties, the Supplier has the sole obligation of making appropriate arrangements with the Distribution Company, and any arrangements which may be necessary with the ISO so that Participating Consumers receive the electricity supplies to be delivered pursuant to this Agreement. The Compact specifically authorizes the Distribution Company to provide, and Supplier the right to obtain and utilize as required, twenty-four (24) months' of historic usage and billing data for each Participating Consumer in an electronic form. If further action is required by the Distribution Company to authorize Supplier to receive such historical energy consumption and billing data, the Compact agrees to use reasonable efforts, at Supplier's cost, to assist Supplier, if so requested by it, in obtaining such information for Participating Consumers, including, without limitation, assisting Supplier in obtaining permission from such Participating Consumers and/or the DTE, where necessary as a prerequisite to the provision of such information.

2.2 **Agency Relationship** - The Compact is authorized to act on behalf of the Member Municipalities in contracting for electric supply for Eligible Consumers. The Compact shall seek a resolution from each Member Municipality approving the Supplier as the opt-out competitive supplier for all Eligible Consumers subject to the terms of this Agreement. In any litigation arising under this Agreement, only the Compact has the right to bring claims against the Supplier.

2.3 **Compliance with Laws** - By entering into this Agreement, the Supplier specifically represents that it has exercised due diligence to review and has fully complied with all relevant regulations and orders of the Federal Energy Regulatory Commission, the DTE, the Office of the Massachusetts Attorney General, and the Massachusetts Division of Energy Resources and any other governmental authorities having jurisdiction over any element of the transactions contemplated by this Agreement.

2.4 **Condition Precedent** - The Parties' obligations under this Agreement shall be conditioned upon a) the Compact receiving approval of this Agreement including, without limitation, the pricing terms by the DTE prior to the close of business on December 1, 2003 and b) the price offered by Supplier as specified in Exhibit A being lower than the the Distribution Company's Default Service tariff rates for the period January 1, 2004 through June 30, 2004. If such approval by the DTE has not been obtained by the close of business on December 1, 2003, either Party may terminate this Agreement without any liability to the other Party.

ARTICLE 3 CUSTOMER CHOICE, NOTIFICATION OF OPT-OUT RIGHTS, ENROLLMENT

3.1 **Customer Choice** - The Parties acknowledge and agree that all Participating Consumers have the right, pursuant to the Restructuring Act, to change their source of electricity supply. The Compact, or Participating Consumers, as the case may be, shall give reasonable notice of any such changes in accordance with the procedures established by the Compact, the Distribution Company and the Supplier pursuant to the terms of the Pilot Project. The Parties represent and warrant to each other that they shall not unreasonably interfere with the right of Participating Consumers to opt-out of the Pilot Project, and shall comply with any rules, regulations or policies of the DTE, the Distribution Company and/or other lawful Governmental Authority regarding the procedures for opting out or of switching from one source of electric supply to another. Notwithstanding the foregoing, however, the Parties may make certain efforts with the intent of seeking commercial and industrial customers to affirmatively agree to remain in the Pilot Project, consistent with any Governmental Rules.

3.2 **Notification to Eligible Consumers of Opt-Out Rights** - Consistent with the requirements of any Governmental Rules and following, in a timely fashion, approval by the DTE of this Agreement, the Supplier shall continue to notify all new Eligible Consumers who are automatically enrolled in Default Service that Supplier will be providing electrical supply to such new Eligible Consumers subject to the opt-out provisions of the Restructuring Act, the Aggregation Plan and the Pilot Project. The opt-out notice shall be mailed to new Eligible Consumers shortly after the customer is auto-enrolled. The notification shall: (1) prominently state all charges to be made by the Supplier; (2) provide a summary of the price included in Exhibit A as well as fully disclose the prices and terms then being offered for Default Service by the Distribution Company; and (3) state how any new Eligible Consumer may opt-out of the Pilot Project after auto-enrollment and choose Default Service from the Distribution Company; and (4) state how all Participating Consumers will also have the right to opt-out at any time and return to Default Service or choose a new competitive supplier without paying a fee or penalty to Supplier. All such notices must be approved in advance by the Compact, such approval not to be unreasonably withheld. In providing the notifications set forth in this Article, and in otherwise conducting the activities in Article 3.3 below, neither the Supplier nor the Compact makes any warranty or representation, express or implied, about the accuracy of any data or other information provided to it by the Distribution Company and, accordingly, is not responsible for any errors or omissions in connection with the notification to new Eligible Consumers.

3.3 **Auto-Enrollment** - All new Eligible Consumers will be automatically enrolled in the Pilot Project at the price set forth in Exhibit A. Promptly upon approval of this Agreement by the DTE, the Compact shall notify the Distribution Company of such approval. Eligible Customers shall be auto-enrolled consistent with the existing auto-enroll procedures. In no event shall either Party be any way responsible for the accuracy or timeliness of any information provided by the Distribution Company or any omissions therein.

ARTICLE 4 TERM OF CONTRACT AND TERMINATION

4.1 **Term** - This Agreement and the rights granted under it to the Supplier shall terminate on December 31, 2004, unless (a) the Agreement is terminated or extended under the provisions of Article 4.3, or (b) the Agreement is terminated before such date under the provisions of Article 4.4.

4.2 **Acceptance and Effective Date** - This Agreement shall be effective and in full force upon execution by the Compact and the Supplier.

4.3 **Automatic Termination and/or Extension** -

A. If the Distribution Company's Default Service tariff rates for the period July 1, 2004 through December 31, 2004 are lower than the price offered by Supplier as specified in Exhibit A, this Agreement shall automatically terminate on June 30, 2004. In the event this Agreement automatically terminates as described above, Supplier and/or the Distribution Company shall promptly notify Participating Consumers that they will be transferred or returned to Default Service from the Distribution Company.

B. Provided that Supplier shall continue to offer a price at a discount to the Distribution Company's Default Service tariff rates, this Agreement may be extended one year beyond December 31, 2004 by mutual, written agreement of the Parties, further subject to the receipt of any and all required regulatory approvals. Such new pricing terms shall be added to and replace Exhibit A as Exhibit A-2. Upon such extension, this Agreement shall continue to be in effect, and all provisions of the Agreement shall retain the same force and effect as before the extension, unless it is terminated by either Party pursuant to the provisions of Article 4.4 or until the date stated in such extension.

4.4 **Events of Default** - An "Event of Default" shall mean, with respect to a Party, the occurrence of any of the following:

(1) the failure to perform any material provision or condition of this Agreement if such failure is not remedied within thirty (30) days following written notice to do so by the other party; or

(2) the failure of the Supplier to provide or arrange for All-Requirements Power Supply to Participating Consumers, in the absence of *Force Majeure* or the Compact's failure to perform, provided that such failure is not the result of actions or non-actions by any transmission service provider, the Distribution Company, or the ISO, and further provided that in the case of such failure there shall be no cure period.

4.5 **Termination Following an Event of Default** – Either Party may terminate this Agreement, upon written notice to the other Party, following an Event of Default. The Parties shall each discharge by performance all obligations due to any other Party that arose up to the date of termination of the Agreement. Upon the effective date of termination of the Agreement, all rights and privileges granted to the Supplier shall cease, with the exception of the right to collect all monies due for services rendered to that date. If this Agreement is automatically terminated under Article 4.3(A), the Supplier shall not be liable to the Compact, the Member Municipalities or any Participating Consumers for any damages resulting from such termination including, without limitation, any costs incurred by the Compact to obtain a replacement supplier, if any. Notwithstanding the foregoing, if this Agreement is terminated pursuant to Article 4.4, Supplier's sole and exclusive liability shall be, any direct, actual costs for electric energy that any such Participating Consumers incur in excess of the prices established in this Agreement as a result of the termination of this Agreement on account of a breach by Supplier. The Compact shall cooperate with Supplier to the fullest extent reasonably possible to ensure that Supplier is not subjected to duplicative claims, arising out of Supplier's breach of its delivery obligations to such Participating Consumers and/or Member Municipalities. In addition, the Supplier shall pay the Compact's reasonable out-of-pocket costs, not to exceed ninety thousand dollars ($90,000), in obtaining or seeking to obtain a replacement supplier in the event this Agreement is terminated under Article 4.4. Upon request, the Compact shall provide reasonably detailed documentation to Supplier to support the costs incurred by the Compact to obtain a replacement supplier. Notwithstanding the foregoing, Mirant specifically reserves all rights it may have at law to claim that the Compact and/or Member Municipalities have no standing or otherwise lack the authority to seek monetary damages on behalf of individual Participating Consumers in the event of a termination of this Agreement.

4.6 **Bankruptcy** - THE COMPACT ACKNOWLEDGES THAT ON JULY 14, 2003, SUPPLIER FILED A VOLUNTARY PETITION FOR RELIEF UNDER CHAPTER 11 OF THE UNITED STATES BANKRUPTCY CODE (CASE NO. 03-46590) (THE "FILING") AND THAT SUCH CASE IS PENDING IN THE UNITED STATES BANKRUPTCY COURT, NORTHERN DISTRICT OF TEXAS, FORT WORTH DIVISION ("BANKRUPTCY COURT"). UNTIL SUCH TIME AS SUPPLIER EMERGES FROM CHAPTER 11 BANKRUPTCY THROUGH THE CONFIRMATION OF A PLAN OF REORGANIZATION, THE FILING SHALL NOT CONSTITUTE AN EVENT OF DEFAULT UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT IN THE EVENT THAT (A) SUPPLIER FILES A MOTION WHICH CONTEMPLATES THE SALE OF SUBSTANTIALLY ALL OF ITS ASSETS; (B) SUPPLIER FILES A CHAPTER 11 PLAN WHICH CONTEMPLATES THE SALE OF SUBSTANTIALLY ALL OF ITS ASSETS; (C) SUPPLIER FILES A MOTION OR REQUEST TO CONVERT ITS CHAPTER 11 CASE TO A CHAPTER 7 PROCEEDING; (D) THE BANKRUPTCY COURT ENTERS AN ORDER CONVERTING SUPPLIER'S CASE FROM A CHAPTER 11 PROCEEDING TO A CHAPTER 7 PROCEEDING; OR (E) THE BANKRUPTCY COURT ENTERS AN ORDER APPOINTING A TRUSTEE OR EXAMINER (WITH EXPANDED POWERS) IN SUPPLIER'S BANKRUPTCY CASE, ANY SUCH EVENT (A) THROUGH (E) SHALL CONSTITUTE AN EVENT OF DEFAULT UNDER THIS AGREEMENT.

4.7 **Supplier Representation Regarding Bankruptcy Matters** - Supplier believes that it has the full right and authority to enter into this Agreement without further approval of the Bankruptcy Court. However, if this Agreement requires approval, in Supplier's reasonable opinion, by the creditors' and equity committees and/or the Bankruptcy Court, neither Party will be bound under this Agreement until Supplier has obtained such approvals; and further, Supplier agrees to promptly seek such approvals if required or if Supplier's ability to enter into this Agreement without such approvals is challenged by a third party including, but not limited to, the DTE or any party to any proceedings regarding this Agreement. Each of Supplier and the Compact reserves the right to request the Bankruptcy Court approval.

ARTICLE 5 CONTINUING COVENANTS

The Supplier agrees and covenants to perform each of the following obligations during the term of this Agreement.

5.1 **Standards of Management and Operations** - In performing its obligations hereunder, during the term of this Agreement, the Supplier shall exercise reasonable care to assure that its facilities are prudently and efficiently managed; that it employs an adequate number of competently trained and experienced personnel to carry out its responsibilities; that it delivers a safe and reliable supply of such amounts of electricity to the Point of Delivery as are required under this Agreement; that it complies with all relevant industry standards and practices for the generation and supply of electricity to Participating Consumers; and that, at all times with respect to Participating Consumers, it exercises the highest commercial standards and employs Commercially Reasonable skills, systems and methods available to it. To the extent Supplier or its affiliates owns or controls the Canal generating facility, the Supplier shall ensure that the Canal generating facility conforms with all Governmental Rules related to emissions. In the event Supplier's affiliate is allegedly in violation of any Governmental Rules related to emissions, the Compact shall have the right to terminate this Agreement, provided, however, the Compact's termination right shall be suspended during the time period Supplier's affiliate is defending, in good faith, any alleged violations. If the alleged violation has not been resolved within six months from the initial report of the violation, the Compact's termination right shall be reinstated. If the Compact exercises its termination right pursuant to this Article 5.1, the Supplier shall not be liable to the Compact or the Member Municipalities for any damages resulting from such termination.

5.2 **Local Customer Service Access** - The Supplier agrees to provide, or cause to be provided, certain customer services to Participating Consumers. Such services shall be reasonably accessible to all Participating Consumers, shall be available during normal working hours, shall allow Participating Consumers to transact business they may have with the Supplier, and shall serve as a communications liaison among the Supplier, the Compact, and the Distribution Company. A toll-free telephone number will be available for Participating Consumers to contact Supplier to resolve concerns, answer questions and transact business with respect to the service received from Supplier. The customer services described above shall commence January 1, 2004 and shall continue for a period of ninety (90) days following the termination of this Agreement.

5.3 **Responding to Requests for Information** - To the extent authorized by the Participating Consumer(s) and to the extent such individual permission is required by law, the Supplier shall, during normal business hours, respond promptly and without charge therefore to reasonable requests of the Compact for information or explanation regarding the matters covered by this Agreement and the supply of electricity to Participating Consumers. The Supplier agrees to designate a service representative or representatives (the "Service Contacts") who shall be available for these purposes, and shall identify the office address and telephone number of such representative(s). Whenever necessary to comply with this Article 5.3, the service representative(s) shall call upon other employees or agents of the Supplier to obtain such information or explanation as may be reasonably requested. Nothing in this Article 5.3 shall be interpreted as limiting the obligation of the Supplier to respond to complaints or inquiries from Participating Consumers, or to comply with any regulation of the DTE or Attorney General regarding customer service.

5.4 **Arranging for Firm All-Requirements Power Supply** - The Supplier shall participate in or make appropriate arrangements with the ISO, any relevant regional transmission organization, wholesale suppliers or any other entity to ensure an uninterrupted flow of reliable, safe, firm, All-Requirements Power Supply to the Distribution Company for delivery to Participating Consumers, and take Commercially Reasonable steps to cooperate with the New England Power Pool ("NEPOOL"), the ISO or any other entity to ensure a source of back-up power in the event that the facilities owned or controlled by Supplier's affiliates or other sources of power supply are unable to generate and/or deliver All-Requirements Power Supply to the Point of Delivery. In the event the Supplier is unable to deliver sufficient electricity to the grid to serve Participating Consumers, the Supplier shall utilize such arrangements as may be necessary to continue to serve Participating Consumers under the terms of this Agreement, and shall bear any costs it may incur in carrying out these obligations. The Supplier shall not be responsible to the Compact, any Member Municipality or any Participating Consumers in the event the Distribution Company disconnects, curtails or reduces service to Participating Consumers (notwithstanding whether such disconnection is directed by the ISO) in order to facilitate construction, installation, maintenance, repair, replacement or inspection of any of the Distribution Company's facilities, to maintain the safety and reliability of the Distribution Company's electrical system, or due to any other reason, including emergencies, forced outages, potential overloading of the Distribution Company's transmission and/or distribution circuits, *Force Majeure* or the non-payment of any distribution service costs or other such costs due for services provided by the Distribution Company to a Participating Consumer.

5.5 **Non-Discriminatory Provision of Service** - Subject to the prices and terms contained in Exhibit A, Supplier shall deliver electricity on a non-discriminatory basis; provided, however, that prices and other terms may vary in accordance with reasonably established classes of customers (e.g., residential, commercial, municipal, industrial) or by such other categories as appear in Exhibit A. To the extent applicable, the Supplier's prices, terms and conditions shall be in accordance with the Massachusetts General Laws, the regulations of the DTE, and other applicable Governmental Rules. To the extent required by any Governmental Rule and/or the conditions of any DTE approval of this Agreement, the Supplier may not deny service to an Eligible Consumer for failure to pay the bills of any other electric company (whether engaged in the distribution, transmission, or generation of electricity) or of any other aggregator, marketer or broker of electricity, but may reasonably deny or condition

service, or terminate existing service, based upon any Participating Consumer's failure to pay bills from the Supplier, subject to any Governmental Rules. Provision of electric energy supply shall be subject to Supplier's standard credit policies (to the extent permitted by law) as described in Exhibit A.

5.6 **Energy Efficiency and Renewable Energy Programs** - The Parties have a mutual interest in advancing the utilization of demand-side management, energy efficiency programs and technology, and renewable energy programs. The Supplier, upon reasonable request of the Compact, shall cooperate with the Compact regarding the implementation of such programs. At no time will Supplier take any actions with the intention of materially adversely affecting the operations of any of these programs. Supplier will use Commercially Reasonable efforts to identify any actions which might have a material adverse effect on the implementation of any programs involving demand-side management, energy efficiency and renewable energy and will use Commercially Reasonable efforts to consult with the Compact prior to taking such actions.

5.7 **Approval of General Communications** - The Supplier shall cooperate with the Compact in the drafting and sending of messages and information to Eligible Consumers and/or Participating Consumers concerning the Compact or any matter arising under or related to this Agreement. The Supplier shall, prior to sending any direct mail, advertising, solicitation, bill insert, electronic mail, or other similar written or electronic communication (collectively, "general communications") to Participating Consumers (but excluding individually drafted or tailored communications responding to the specific complaint or circumstance of an individual consumer), provide a copy of such general communication to the Compact for its review to determine whether it is consistent with the purposes and goals of the Compact. The Compact shall have the right to disapprove such general communications and suggest revisions if it finds the communication inconsistent with the purposes and goals of the Compact, factually inaccurate or likely to mislead; provided, however: (i) that the communication shall be deemed approved if the Compact fails to respond within seven calendar days (not including weekends and holidays); and (ii) that no approval shall be necessary for any communication (a) regarding any emergency situation involving any risk to the public health, safety or welfare; (b) which has been approved by the DTE, the Division of Energy Resources, or any other Governmental Authority; or (c) in the nature of routine monthly or periodic bills, or collection notices, except that any bill insert or message included at the bottom of such bill not within the scope of (a) or (b) above shall require approval. If the Compact disapproves any general communication on the grounds it is inconsistent with the purposes and goals of the Compact, the Supplier, after consultation as provided in this Article 5.7, may nevertheless elect to send such general communication provided that it: (i) clearly indicates on such mailing that it has not been endorsed by the Member Municipality and/or the Compact, (ii) has previously provided all Participating Consumers a meaningful chance to opt not to receive such general communications, (iii) has stated in connection with such chance to opt not to receive such communications that "the Compact and the Member Municipalities want to protect Consumers from receiving marketing materials if you do not wish to do so," and (iv) has otherwise sought input from the Compact as to the means by which Consumers are given a chance to remove their names from any list which may receive general communications.

5.8 **Bill Inserts and Messages** - The Supplier agrees that if it bills or communicates with Participating Consumers directly, and unless prevented for regulatory or other such reasons from doing

so, it shall allow the Compact to include no less than three bill inserts per year into such billings, provided that the Compact pays the cost of printing and reproducing such insert and any incremental postage or handling costs the Supplier may incur as a result of including such insert. The Supplier further agrees that it shall, at its direct cost, if any, and to the extent that it does not conflict with planned use of any message space by the Supplier, provide the Compact access to any message space on any bills the Supplier sends to Participating Consumers, to the extent any bills it sends directly or indirectly through the Distribution Company or other entity contain a bill message space under the control of the Supplier. Supplier shall have the right to disapprove such general communications (that is communications other than those pertaining to the Compact's demand-side management, energy efficiency programs and technology, and renewable energy programs) and suggest revisions if it finds the communication inconsistent with its business interests, factually inaccurate or likely to mislead; provided, however: (i) that the communication shall be deemed approved if the Supplier fails to respond within seven calendar days (not including weekends and holidays); and (ii) that no approval shall be necessary for any communication which has been ordered by the DTE, the Division of Energy Resources, or any other Governmental Authority to be so communicated.

5.9 **Consumer Lists** - To the extent not prohibited by any Governmental Rule or expressly by any Participating Consumer(s), the Supplier shall, upon request of the Compact, provide a list of the Participating Consumers being served by the Supplier, including such reasonable identifying and aggregate consumption information as the Compact may also request to the extent such information is available to Supplier. The Supplier shall provide such consumer lists in an electronic format reasonably acceptable to both Parties and with no more frequency than once a month.

5.10 **Compliance with Laws** - The Parties shall promptly and fully comply with all existing and future Governmental Rules of all Governmental Authorities having jurisdiction over the activities covered by this Agreement.

5.11 **Consent** - Whenever performance of an obligation of any Party hereto requires the consent or approval of any Governmental Authority, such Party shall make Commercially Reasonable efforts to obtain such consent or approval. In the event the Supplier requests the Compact's assistance in obtaining such consent or approval and the Compact anticipates that it (and/or the Member Municipalities) will incur costs in fulfilling the Supplier's request, it shall give the Supplier an estimate of such costs. Upon receiving the estimate, Supplier shall determine if it continues to request the Compact's assistance, and if so, the Supplier shall reimburse the Compact and/or the Member Municipalities for all costs, up to the estimated dollar amount, reasonably incurred by the Compact and/or Member Municipalities in connection with such efforts.

ARTICLE 6 ROLES OF THE COMPACT AND THE MEMBER MUNICIPALITIES

6.1 **In General** - Under this Agreement, neither the Compact nor the Member Municipalities (except as they or entities under their control are Participating Consumers) shall actually receive, take title to, or be liable for the supply or delivery of All-Requirements Power Supply in any manner

whatsoever. The Parties specifically agree that the role of the Compact is to a) set the terms and conditions under which All-Requirements Power Supply will be provided by the Supplier under this Agreement and to ensure that the Supplier complies with those terms and conditions, and b) act as agent for the Member Municipalities with respect to the matters addressed in this Agreement. It is the sole obligation of the Supplier to arrange for delivery of All-Requirements Power Supply to Participating Consumers. The Parties agree that neither the Compact nor the Member Municipalities are "aggregators," "distribution companies," "electric companies," "generation companies" or "transmission companies" within the meaning of G.L. c. 164, §1 as a result of this Agreement, unless a court, the DTE, or other lawful authority shall adjudicate to the contrary; provided, however, that the Member Municipalities and the Compact may be considered to be operating a municipal load aggregation program pursuant to G.L. c. 164, §134. The Supplier hereby agrees that it will take no action that would make the Compact or the Member Municipalities liable to any Eligible or Participating Consumer due to any act or failure to act on the part of the Supplier relating to the delivery or supply of All-Requirements Power Supply.

ARTICLE 7 PRICES AND SERVICES; BILLING

7.1 **Schedule of Prices and Terms** - The Supplier agrees to provide All-Requirements Power Supply and other related services as expressly set forth herein in accordance with the price included in Exhibit A to this Agreement, which Exhibit is hereby incorporated by reference into this Agreement.

7.2 **Obligation to Serve** - As between the Parties, the Supplier has the sole obligation to obtain sources of supply, whether from generating facilities owned or controlled by its affiliates, through bilateral transactions, or the market, as may be necessary to provide All-Requirements Power Supply for all of the Participating Consumers under the Pilot Project. The Supplier shall make appropriate arrangements to obtain such capacity, electrical energy, and ancillary services for load-following purposes, including, but not limited to, spinning reserves, supplemental reserves, backup supplies and services as may be needed in the event of outages or emergencies, and all other ancillary services as necessary to provide a firm, reliable, and safe All-Requirements Power Supply for Participating Consumers to the Point of Delivery. The Supplier, except as explicitly limited by the terms included in Exhibit A, shall be obligated to accept all Eligible Consumers who become participants in the Compact's Pilot Project, subject to the terms of any approval or other order of the DTE with respect to this Agreement.

7.3 **Metering and Billing** - As between the Parties, the Supplier bears sole responsibility for any metering which may be required to bill Participating Consumers, and for rendering of any bills to Participating Consumers. Supplier may discharge this obligation by making appropriate arrangements with the Distribution Company or any other entity. Any metering and billing functions carried out by the Supplier shall be conducted in compliance with relevant rules and regulations of the DTE and the Attorney General of the Commonwealth.

7.4 **Standard Terms and Conditions Pertaining to Individual Account Service** -

A. **Title**

Title to All-Requirements Power Supply will transfer from Supplier to Participating Consumers at the Point of Sale. Possession of, and risk of loss related to, All-Requirements Power Supply will transfer from Supplier to the Distribution Company at the Point of Delivery.

B. **Term**

Delivery of All-Requirements Power Supply will begin on the first meter reading date in January, 2004, as specified in Exhibit A, or as soon as necessary arrangements can be made with the Distribution Company thereafter and will end on the last meter reading date prior to the expiration or termination of this Agreement. Supplier has the right to request a "special" meter reading by the Distribution Company to initiate energy delivery and agrees to accept all costs (if any) for such meter reading.

C. **Billing and Payment**

Unless otherwise specified in an Exhibit to this Agreement, all billing under this Agreement shall be based on the meter readings of each Participating Consumer's meter performed by the Distribution Company. The Supplier shall, or shall cause the Distribution Company or any other entity to, prepare and mail bills to Participating Consumers monthly. If Supplier arranges for the Distribution Company to perform billing services, Supplier shall adopt the billing and payment terms offered by the Distribution Company to its Default Service customers unless the Supplier and Distribution Company otherwise agree. Supplier shall make such billing and payment terms available to Participating Consumers on its website.

D. **Regional and Local Transmission**

The prices quoted in Exhibit A do not include current and future charges for distribution service costs collected by the Distribution Company under its distribution service tariff. If in the future Supplier becomes responsible for distribution costs, Supplier shall be entitled to collect such costs from Participating Consumers to the extent permitted by any Governmental Rules. These costs are "pass through" costs as determined by the appropriate regulatory agencies.

E. **Taxes**

All sales, gross receipts, excise or similar taxes imposed with respect to the sale or consumption of All-Requirements Power Supply shall be included on the Participating Consumer's bill and shall be remitted to the appropriate taxing authority by Supplier. Participating Consumers shall be responsible for all taxes (except for taxes on Supplier's income) associated with sales of All-Requirements Power Supply under this Agreement. Supplier shall make available a service to provide Participating Consumers who are tax-exempt with an exemption from collection of any taxes, however such Participating Consumers shall be responsible for identifying and requesting any exemption from the collection of any tax by providing appropriate documentation to Supplier.

F. **Material and Adverse Change in Law or Regulation**

If at any time during the term of this Agreement (i) a final and unappealable Governmental Rule is instituted, repealed, revised or changed or any other similar unanticipated change in circumstance of a significant magnitude and beyond the reasonable control of the Parties occurs and (ii) such event results in a substantial and material adverse economic impact to the Compact, any Member Municipality or Supplier under this Agreement such that, directly as a result of such Governmental Rule the affected party expects to incur a loss in continuing performance under this Agreement for the remaining term thereof, then the affected party may, upon written notice to the others, invoke this Article 7.4(F) as a basis for immediately initiating good faith negotiations to amend the affected terms of this Agreement. The Parties will negotiate to balance the disparity caused by the event and to restore to the Parties, to the greatest extent possible, the benefit of their respective bargains on the Effective Date. If the Parties are unable to agree on any amendment to this Agreement, any Party may terminate this Agreement, subject to any applicable regulatory requirements and after providing sixty (60) days prior written notice to the DTE and the other Party, without any liability or responsibility except for obligations arising prior to the date of termination and those obligations which expressly survive termination of this Agreement.

G. **Limitation of Liability**

Recognizing that electricity provided hereunder shall be ultimately delivered by the Distribution Company, to the extent permitted by law, Supplier shall not be liable for any damage to a Participating Consumer's equipment or facilities, or any economic losses, resulting directly or indirectly from any service interruption, power outage, voltage or amperage fluctuations, discontinuance of service, reversal of service, irregular service or similar problems beyond Supplier's reasonable control. TO THE EXTENT PERMITTED BY LAW, EXCEPT AS EXPRESSLY STATED IN THIS AGREEMENT, SUPPLIER MAKES NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED (INCLUDING WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR A PARTICULAR PURPOSE) WITH RESPECT TO THE PROVISION OF SERVICES AND ELECTRIC ENERGY HEREUNDER.

H. **No Exemplary, Punitive, Special or Consequential Damages**

THE PARTIES SHALL ONLY BE ENTITLED TO RECOVER ACTUAL DAMAGES FOR A BREACH OR VIOLATION OF THIS AGREEMENT. NO PARTY SHALL BE ENTITLED TO RECOVER EXEMPLARY, PUNITIVE, SPECIAL, CONSEQUENTIAL, INCIDENTAL OR INDIRECT LOSSES OR DAMAGES FROM THE OTHER PARTY IN ANY ARBITRATION PROCEEDING, COURT PROCEEDING, OR OTHERWISE, HOWEVER CAUSED, WHETHER BY A PARTY'S SOLE OR CONCURRENT NEGLIGENCE OR OTHERWISE, AND EACH PARTY HEREBY WAIVES ANY CLAIM OR RIGHT TO EXEMPLARY, PUNITIVE, SPECIAL, INCIDENTAL OR CONSEQUENTIAL DAMAGES HEREUNDER.

I. **Consumer Credit Checks**

Supplier agrees to comply with the requirements of 220 CMR 11.05(3)(d) regarding termination of service to residential customers. To the extent permitted by law, Supplier may, subsequent to the scheduled initiation of service, request access to a Participating Consumer's credit history and may request a security deposit from a non-residential Participating Consumer, in either case only if the Participating Consumer fails to make timely payments on two or more bills. No requested security deposit may exceed two months of actual bills. Supplier may terminate service to a non-residential Participating Consumer who fails to provide the security deposit amounts authorized by this paragraph.

J. **EDI/EFT**

Supplier will provide Electronic Funds Transfer ("EFT") as a payment option to Participating Consumers provided the Participating Consumer and Supplier can mutually access a common Value Added Network ("VAN") and provided further that Supplier is allowed to pass through the costs imposed by VAN providers or the provider of other electronic transmission vehicle. To the extent mutually agreed to by the Parties, Participating Consumers who use EFT as a payment method will receive a percentage discount determined by the Supplier.

ARTICLE 8 DEVELOPMENT OR OFFERING OF RENEWABLE ENERGY SOURCES

8.1 **Compliance with Law** - The Supplier hereby agrees that it will comply with the applicable provisions of G.L. c. 25A, §11F and any regulations, orders or policies adopted pursuant thereto.

ARTICLE 9 SERVICE PROTECTIONS FOR RESIDENTIAL CUSTOMERS

To the extent applicable, Supplier agrees that it shall comply with the provisions of 220 CMR Parts 25, 27, 28 and 29, any amendments thereto, and any code of conduct or policies the DTE may adopt in accordance with G.L. c. 164, §1F(7). The Supplier shall, on or before March 13, 2002, provide a written, detailed description of its billing and termination procedures, customer services, confidentiality and related practices and procedures for approval by the Compact (which approval shall not be unreasonably withheld). Such written description shall also include the Supplier's plans for maintaining "service quality standards," as that phrase is used in §1F(7); for complying with the "affirmative choice" requirements of §1F(7); and for handling customer complaints, including any arbitration procedures. If the Participating Consumer(s) so permit(s) to the extent such permission is required by law or the terms of any DTE order with respect to this Agreement, the Supplier agrees to provide notice to the Compact of any customer complaints received from a Participating Consumer, and to grant the Compact the right to participate in resolution of the dispute, to the extent permitted by DTE regulations and other applicable law. The failure to timely submit such written description, or the submission of practices and procedures which materially fail to comply with DTE regulations and policies, shall be deemed grounds for termination of this Agreement, at the discretion of the Compact after providing written notice of such failure to the Supplier and allowing the Supplier thirty days to cure such failure.

ARTICLE 10 NON-DISCRIMINATION IN HIRING AND EMPLOYMENT

The Supplier agrees to conduct its operations and activities under this Agreement in accordance with all applicable state and federal laws regarding non-discrimination in hiring and employment of employees.

ARTICLE 11 ACCESS TO INFORMATION

11.1 **Power Supply Report** - Supplier shall present a copy of the current "Disclosure Label" required by the DTE of all Competitive Suppliers to be disclosed to their customers which includes information pertaining to their power supply and a reasonably detailed description of the sources of Supplier's power supply used to serve Participating Consumers pursuant to this Agreement, except to the extent such disclosure would violate any confidentiality obligations of Supplier.

11.2 **Books and Records** - The Supplier shall keep its books and records in accordance with any applicable regulations or guidelines of the DTE, the Federal Energy Regulatory Commission, and any other Governmental Authority. The Compact will have access to all reports mandated by the Securities and Exchange Commission which are available on the Internet "EDGAR" system.

11.3 **Copies of Regulatory Reports and Filings** - Upon reasonable request, the Supplier shall provide to the Compact a copy of each public periodic or incident-related report or record relating to this Agreement which it files with any Massachusetts or federal agency regulating rates, service, compliance with environmental laws, or compliance with affirmative action and equal opportunity requirements, unless the Supplier is required by law or regulation to keep such reports confidential from the other Parties. The Compact or any Member Municipality to whom the Compact has provided access shall treat any reports and/or filings received from Supplier as confidential information subject to the terms of Article 16. Supplier shall be reimbursed its reasonable costs of providing such copies.

ARTICLE 12 RESOLUTION OF DISPUTES; CHOICE OF LAW

12.1 **Choice of Law** - This Agreement and the rights of the Parties shall be interpreted and determined in accordance with the laws of the Commonwealth of Massachusetts.

12.2 **Dispute Resolution** - The Parties shall attempt to resolve any dispute, controversy or claim arising out of or relating to this Agreement, or the breach, termination or validity hereof by negotiation between representatives who will have the authority to resolve the dispute. Any Party may give the other Party written notice of any dispute not resolved in the ordinary course of business. Within ten (10) days after delivery of such notice, the representatives shall attempt to meet at a mutually acceptable time and place to resolve the dispute. If such designated representatives are unable to resolve the dispute within thirty (30) days of receipt of notice of the dispute, either party may bring an action in any court in Suffolk County in the Commonwealth of Massachusetts. In any such judicial action, the "Prevailing Party" shall be entitled to payment from the opposing Party of its reasonable costs and fees,

including, but not limited to, attorneys' fees, arising from the civil action. As used herein, the phrase "Prevailing Party" shall mean the Party who, in the reasonable discretion of the finder of fact, most substantially prevails in its claims or defenses in the civil action. Notwithstanding the preceding sentence, the costs and fees payable by the opposing Party shall not exceed an aggregate amount of $250,000 for all civil actions arising under this Agreement.

ARTICLE 13 INDEMNIFICATION

13.1 **Indemnification by Supplier** - Subject to the limitation of damages in Article 7.4(H), Supplier shall indemnify, defend and hold harmless the Member Municipalities and the Compact (collectively "Indemnified Parties" and singularly "Indemnified Party") and each Indemnified Party's officers, employees, agents, representatives and independent contractors, from and against any and all costs, claims, liabilities, damages, expenses (including reasonable attorneys' fees), causes of action, suits or judgments, incurred by, on behalf of or involving any one of the foregoing parties to the extent arising, directly or indirectly, from or in connection with (i) any material breach by Supplier of its obligations, covenants, representations or warranties contained in this Agreement and not resulting from the actions and/or non-actions of the Distribution Company, the Compact or any Member Municipality or their employees or agents, or (ii) Supplier's actions or omissions taken or made in connection with Supplier's performance of this Agreement. Supplier further agrees, if requested by the Compact or any Member Municipality, to investigate, handle, respond to, and defend any such claim, demand, or suit at its own expense arising under this Article 13.1. Should Supplier defend any such claim against the Compact or any Member Municipality hereunder, it shall have full control of such defense, in its reasonable discretion.

13.2 **Notice of Indemnification Claims** - If the Compact seeks indemnification pursuant to this Article 13, it shall notify Supplier of the existence of a claim, or potential claim as soon as practicable after learning of such claim, or potential claim, describing with reasonable particularity the circumstances giving rise to such claim. Upon written acknowledgment by the Supplier that it will assume the defense and indemnification of such claim, the Supplier may assert any defenses which are or would otherwise be available to the Compact.

13.3 **Survival** - Notwithstanding any provision contained herein, the provisions of this Article 13 shall survive the termination of this Agreement for a period of three (3) years with respect to any claims which occurred or arose prior to such termination.

ARTICLE 14 REPRESENTATIONS AND WARRANTIES

14.1 **Representations and Warranties -**

A. As a material inducement to entering into this Agreement, the Supplier hereby represents and warrants to the Compact as of the Effective Date of this Agreement as follows:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary for it to perform its obligations under this Agreement;

(ii) it has all authorizations from any Governmental Authority necessary for it to legally perform its obligations under this Agreement or will obtain such authorizations in a timely manner prior to when any performance by it requiring such authorization becomes due;

(iii) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a party or any Governmental Rule applicable to it;

(iv) subject to the conditions set forth in Article 2.4, this Agreement constitutes a legal, valid and binding obligation of the Supplier enforceable against it in accordance with its terms, and the Supplier has all rights such that it can and will perform its obligations to the Compact in conformance with the terms and conditions of this Agreement, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally and general principles of equity.

B. As a material inducement to entering into this Agreement, the Compact hereby represents and warrants to Supplier as of the effective date of this Agreement as follows:

(i) the Compact was formed by intergovernmental agreement in accordance with the laws of the Commonwealth of Massachusetts;

(ii) this Agreement will (subject to the Governmental approvals described in Article 2.4 above) constitute the legal, valid and binding obligation of the Compact enforceable in accordance with its terms;

(iii) the execution, delivery and performance of this Agreement are within the Compact's powers, have been or will be duly authorized by all necessary action and the Compact is the duly authorized agent of the Member Municipalities with respect to the matters addressed in this Agreement;

(iv) the Compact has all authorizations from any Governmental Authority necessary for it to legally perform its obligations under this Agreement or will obtain such authorizations in a timely manner prior to when any performance by it requiring such authorization becomes due; and

(v) to the best of its knowledge, but without independent inquiry, no Bankruptcy is pending or threatened against any of the Member Municipalities.

C. Each Party further represents and warrants:

(i) The Parties have negotiated and entered into this post-petition Agreement in the ordinary courses of their respective businesses, in good faith, for fair consideration and on an arm's length basis; and

(ii) Neither Party shall attempt to effect any right of set-off with respect to this such post-petition Agreement and any pre-petition obligations.

ARTICLE 15 INSURANCE AND RESERVE FUND

15.1 **Insurance** - In order to help support the indemnifications provided in Article 13, and its other promises and covenants stated herein, Supplier shall secure and maintain, at its own expense, throughout the term of this Agreement, comprehensive commercial general liability insurance of at least $5,000,000 combined single limit and excess liability coverage of at least $5,000,000 with insurers and with the Compact and Member Municipalities named as additional insureds. Supplier shall provide the Compact with evidence, reasonably satisfactory to the Compact, of its insurance hereunder, upon request. The detailed terms of Supplier's insurance are set forth in Exhibit B attached hereto.

15.2 **Reserve Fund** - In order to ensure timely access to funds and: (a) provide the Compact with further financial security in the event Supplier declines to or otherwise fails to indemnify it pursuant to Article 13 and that the insurance coverage pursuant to Article 15.1 is unavailable or insufficient, and (b) provide the Compact with a special reserve fund ("Reserve Fund") to give further assurances that the Compact will be able to respond appropriately to any risks associated with this Agreement, Supplier agrees to collect on behalf of the Compact, one mill ($.001) or such lesser number as the Compact may specify (including zero) for every kWh sold to Participating Consumers during calendar year 2004. Supplier shall remit to the Compact or its designee on a monthly basis, by electronic funds transfer or such other mutually acceptable method, the amounts due pursuant to this Article 15.2 and provide reasonable supporting documentation as to the total number of kWh sold in each preceding month upon which such payment is calculated.

Once paid to the Compact or its designee, Supplier shall have no further interest or claim in such Reserve Fund. The Compact may use the Reserve Fund to cover any costs, claims, liabilities, damages, expenses (including reasonable attorney's fees), causes of action, suits or judgments, incurred by or on behalf of the Compact or Member Municipalities. The Compact shall cause all funds collected for it by Supplier hereunder to be deposited in a dedicated, interest-bearing account and shall keep records of the receipts, expenditures and balance in such account which shall be provided on a quarterly basis to Supplier and any governmental agencies which may request such records. These records shall be a matter of public record pursuant to G.L. c. 4, §7, cl. 26 and G.L. c. 66, §10. To the extent there

are funds remaining in the Reserve Fund at the expiration or termination of this Agreement (and after the running of any statute of limitations periods which the Compact may deem appropriate or prudent), the Compact may expend such funds and/or rebate them to Participating Consumers for any purpose as may be allowed by law and shall be determined in the sole reasonable discretion of the Compact's Governing Board.

ARTICLE 16 CONFIDENTIALITY

Supplier acknowledges that the Compact is subject to public records laws, including without limitation, G.L. c. 4, §7, cl. 26 and G.L. c. 66, §10. To the extent not prohibited by such laws, all Parties shall keep confidential, and shall not disseminate to any third party (other than such Party's affiliates) or use for any other purpose (except with written authorization, such authorization not to be unreasonably withheld), any information received from the other that is confidential or proprietary in nature unless legally compelled (by deposition, inquiry, request for production of documents, subpoena, civil investigative demand or similar process, or by order of a court or tribunal of competent jurisdiction, or in order to comply with applicable rules or requirements of any stock exchange, government department or agency or other Governmental Authority, or by requirements of any securities law or regulation or other Governmental Rule) or as necessary to enforce the terms of this Agreement. Either Party may disclose the terms of this Agreement to (i) its affiliates, and to its and their officers, directors, employees, attorneys and accountants, and (ii) the Member Municipalities, who are bound to hold, treat and protect such information on a confidential basis. This Article 16 shall survive the termination of this Agreement for a period of two (2) years. If any Party is compelled to disclose any confidential information of the other Party, such Party shall request that such disclosure be protected and maintained in confidence to the extent reasonable under the circumstances and use reasonable efforts to protect or limit disclosure with respect to commercially sensitive terms. In addition, notwithstanding the public records laws referenced above, such Party shall provide the other Party with prompt notice of the requirement to disclose confidential information in order to enable the other Party to seek an appropriate protective order or other remedy, and such Party shall consult with the other Party with respect to the other Party taking steps to resolve the scope of any required disclosure. In the event the Supplier requests the Compact's assistance in protecting the of confidentiality of information and the Compact anticipates that it and/or the Member Municipalities will incur costs in fulfilling the Supplier's request, it shall give the Supplier an estimate of such costs. Upon receiving the estimate, Supplier shall determine if it continues to request the Compact's assistance, and if so, the Supplier shall reimburse the Compact and/or Member Municipalities for all costs, up to the estimated amount, reasonably incurred by the Compact and/or Member Municipalities in connection with such efforts.

For the avoidance of doubt, the information related to this Agreement that is considered confidential and proprietary in nature shall include the following:

(i) any account information related to the Participating Consumers including, without limitation, historic usage data, metering, and billing and payment information;

(ii) any information regarding transactions entered into by Supplier and any third parties in connection with the provision of All-Requirements Power Supply;

(iii) any list of Participating Consumers;

(iv) any information disclosed by a Party during any settlement discussions;

(v) Supplier's insurance policies;

(vi) any non-public information provided by Supplier pursuant to Section 15.2 of this Agreement; and

(vii) any information which either Party should reasonably understand to be confidential and proprietary by virtue of the sensitive nature of the information.

ARTICLE 17 MISCELLANEOUS

17.1 **No Assignment Without Permission** - Neither Party shall assign its rights and privileges under this Agreement without the prior written approval of the other Party and such approval may be denied in the reasonable discretion of the non-assigning Party if it determines that the proposed assignee does not have at least the same financial ability as the assigning Party and, in the event of a proposed assignment by Supplier, that it does not meet the objectives as set forth in Article 1 of the Compact Agreement. Notwithstanding the foregoing, the Compact may not unreasonably withhold its consent to an assignment to an affiliated entity under common control or management with Supplier. Further, a sale of 50% or more of the interests of Supplier in this Agreement shall be considered an assignment if, and only if, such sale results in a change in the control and the management of Supplier's operation. Any assignee shall agree in writing to be bound by the terms and conditions of this Agreement. The rights and obligations created by this Agreement shall inure to the benefit of, and be binding upon, the successors and permitted assigns of, the respective Parties hereto.

17.2 **Direct Marketing** - Prior to the introduction of any new product or service which Supplier may wish to make available to Participating Consumers or other consumers located with a Member Municipality, Supplier agrees to (i) give the Compact written notice of such new product or service and (ii) subject to the entry into reasonable confidentiality terms to the extent permitted by law and mutually acceptable to the Parties, discuss with the Compact the possible inclusion of such new product or service in this or another aggregation program undertaken by the Compact and Member Municipalities in the geographic area encompassing the Member. The Parties agree to negotiate in good faith the terms, conditions, and prices for such products and services which the Parties agree should be included in a Compact aggregation program.

The Supplier also agrees not to engage in any direct marketing to any Participating Consumer that relies upon the Supplier's unique knowledge of, or access to, Participating Consumers (including addresses, telephone numbers or other identifying information) gained as a result of this Agreement, if so requested by such Participating Consumer as set forth in Article 5.7 hereof. For the purposes of this provision, "direct marketing" shall include any telephone call, mailing, electronic mail, or other contact between the Supplier and the Consumer. Broad-based programs of the Supplier that do not rely on unique knowledge or access gained through this Agreement will not constitute such "direct marketing." Supplier further expressly agrees not to sell, disclose or otherwise transfer identification or identifiable information about Participating Consumers (including addresses, telephone numbers or other identifying

information) gained as a result of this Agreement except with the express permission of the Participating Consumer.

17.3 **Notices** - All notices, demands, requests, consents or other communications required or permitted to be given or made under this Agreement shall be in writing and

if to Supplier to:

Mirant Americas Retail Energy Marketing, LP
Attention: Legal Department
1155 Perimeter Center West, Suite 130
Atlanta, Georgia 30338

if to the Compact to:

Ms. Margaret T. Downey
Administrator
Cape Light Compact
P.O. Box 427
Superior Court House
Barnstable, Massachusetts 02630
(508) 375-6636 (voice)
(508) 362-4136 (fax)
mags@cape.com

Notices hereunder shall be deemed properly served (i) by hand delivery, on the day and at the time on which delivered to the intended recipient at the address set forth in this Agreement; (ii) if sent by mail, on the third business day after the day on which deposited in the United States certified or registered mail, postage prepaid, return receipt requested, addressed to the intended recipient at its address set forth in this Agreement; or (iii) if by Federal Express or other reputable express mail service, on the next business day after delivery to such express mail service, addressed to the intended recipient at its address set forth in this Agreement. Any party may change its address and contact person for the purposes of this Article 17.3 by giving notice thereof in the manner required herein.

17.4 **Changes in Emergency and Service Contact Persons** - In the event that the name or telephone number of any emergency or service contact for the Supplier changes, Supplier shall give prompt notice to the Compact in the manner set forth in Article 17.3. In the event that the name or telephone number of any such contact person for the Compact changes, prompt notice shall be given to the Supplier in the manner set forth in Article 17.3.

17.5 **Entire Agreement; Amendments** - This Agreement and the Related Documents, as set forth in Article 17.13, constitute the entire agreement between the Parties hereto with respect to the subject matter hereof and supersedes all prior oral or written agreements and understandings between the

Parties relating to the subject matter hereof. This Agreement may only be amended or modified by a written instrument signed by all Parties hereto.

17.6 ***Force Majeure*** - If by reason of *Force Majeure* any Party is unable to carry out, either in whole or in part, its obligations herein contained, such Party shall not be deemed to be in default during the continuation of such inability, provided that: (i) the non-performing Party, within two (2) weeks after the occurrence of the *Force Majeure*, gives all other Parties hereto written notice describing the particulars of the occurrence; (ii) the suspension of performance be of no greater scope and of no longer duration than is required by the *Force Majeure*; (iii) no obligations of the Party which were to be performed prior to the occurrence causing the suspension of performance shall be excused as a result of the occurrence; and (iv) the non-performing Party shall use Commercially Reasonable efforts to remedy with all reasonable dispatch the cause or causes preventing it from carrying out its obligations.

17.7 **Expenses** – Every Party hereto shall pay all expenses incurred by it in connection with its entering into this Agreement, including, without limitation, all attorneys' fees and expenses.

17.8 **No Joint Venture** - Supplier will perform all services under this Agreement as an independent contractor. Nothing herein contained shall be deemed to constitute any Party a partner, agent or legal representative of the other Party or to create a joint venture, partnership, agency or any relationship between the Parties. The obligations of the Compact and the Supplier hereunder are individual and neither collective nor joint in nature.

17.9 **Joint Workproduct** - This Agreement shall be considered the workproduct of all Parties hereto, and, therefore, no rule of strict construction shall be applied against any Party hereto.

17.10 **Counterparts** - This Agreement may be executed in counterparts, each of which shall be deemed an original and all of which shall constitute a single agreement.

17.11 **Waiver** - No waiver by any Party hereto of any one or more defaults by any other Party in the performance of any provision of this Agreement shall operate or be construed as a waiver of any future default, whether of like or different character. No failure on the part of any Party hereto to complain of any action or non-action on the part of any other Party, no matter how long the same may continue, shall be deemed to be a waiver of any right hereunder by the Party(ies) so failing. A waiver of any of the provisions of this Agreement shall only be effective if made in writing and signed by the Party who is making such waiver.

17.12 **Cooperation** - Each Party acknowledges that this Agreement must be approved by the DTE and agree that they shall use Commercially Reasonable efforts to cooperate in seeking to secure such approval.

17.13 **Related Documents** - The Supplier agrees that it has been provided with and had a reasonable opportunity to read the Compact Agreement, the Aggregation Plan, the Participation Agreement between Barnstable County, Cape Light Compact, County of Dukes County and Vineyard Towns, and the Administrative Services Agreement between Barnstable County and Cape Light

Compact, and the Pilot Project (collectively, "Related Documents"). The Parties agree that the Related Documents, in the forms as they exist on the Effective Date of this Agreement, are incorporated into this Agreement by reference, and that they shall be construed harmoniously to the greatest practicable extent; notwithstanding the foregoing, in the event of any conflict between this Agreement and the Related Documents, this Agreement shall govern. The Compact will provide Supplier with amendments to any of the foregoing documents as they are adopted; provided, however, that such amendments are not incorporated into this Agreement as a result of such adoption. Any amendments hereto must be made in accordance with Article 17.5 of this Agreement.

17.14 **Advertising Limitations** - The Supplier agrees not to use the name of the Cape Light Compact, or make any reference to the Cape Light Compact in any advertising or other information to be distributed publicly for marketing or educational purposes, unless the Compact expressly agrees to such usage. Any proposed use of the name of the Cape Light Compact must be submitted in writing for agreement and prior approval, which shall not be unreasonably withheld, consistent with Article 5.7 hereof. The Compact acknowledges that the Supplier's corporate affiliates own the exclusive right to the trademarked logo and trade name used by Supplier. No right, license or interest in this trademark and/or trade name is granted to the Compact hereunder, and the Compact agrees that it shall not assert any right, license or interest with respect to such trademark and/or trade name.

17.15 **Press Releases** - The Parties shall not issue a press release or make any public statement with respect to this Agreement without the prior written agreement of the other Party with respect to the form, substance and timing thereof, except either Party may make any such press release or public statement when the releasing Party is advised by its legal counsel that such a press release or public statement is required by law, regulation or stock exchange rules, provided however, in such event, the Parties shall use their reasonably good faith efforts to agree as to the form, substance and timing of such release or statement.

17.16 **Headings and Captions** - The headings and captions appearing in this Agreement are intended for reference only, and are not to be considered in construing this Agreement.

17.17 **Survival of Obligations** - Termination of this Agreement for any reason shall not relieve the Company or Supplier of any obligation accrued or accruing prior to such termination.

17.18 **Duty to Mitigate** - Each Party agrees that it has a duty to mitigate damages and covenants that it will use Commercially Reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written below.

MIRANT AMERICAS RETAIL ENERGY MARKETING, LP
BY: MIRANT AMERICAS DEVELOPMENT, INC.
ITS GENERAL PARTNER

By: ______________________________
Name: ____________________________
Title: _____________________________

Dated: ____________________________

CAPE LIGHT COMPACT

By: ______________________________
Ms. Margaret T. Downey
Administrator
Cape Light Compact
P.O. Box 427
Superior Court House
Barnstable, MA 02630
(508) 375-6636 (voice)
(508) 362-4166 (fax)
mags@cape.com

Dated: ____________________________

EXHIBIT A
PRICES

Pilot Project for Default Service Customers

*****Residential*****	*****Commercial/Industrial*****			
R-1, R-2R-3, R-4, R-5	G-1	G-2, G-3	G-4, G-5,G-6, G-7	S1, S2

January 1, 2004 – December 31, 2004

5.751 cents per kilowatt hour for all rate classes

Note: The price of 5.751 includes a one mill ($.001) adder, pursuant to the Compact's request, for the purpose of establishing a Reserve Fund pursuant to Section 15.2 of the Agreement. At the Compact's request, this adder may be reduced or eliminated.

EXHIBIT B
INSURANCE

1. The Supplier shall maintain commercial general liability insurance throughout the term of the Agreement and for a period of at least two (2) years following the contract term.

2. The insurance may be provided on a claims made basis. In the event such insurance is cancelled or non-renewed, Supplier agrees to provide a 36 month discovery period endorsement for obligations under this Agreement.

3. The insurance shall include coverage for bodily injury liability, property damage liability, advertising injury liability and personal injury liability.

4. To the extent available at commercially reasonable terms and conditions, personal injury liability coverage shall include non-employment discrimination in accordance with AEGIS form 8100 (1/1/98).

5. To the extent available at commercially reasonable terms and conditions, the insurance shall include Failure to Supply coverage and such coverage shall be in accordance with AEGIS form 8100 (1/1/98).

6. The insurance shall include blanket contractual liability coverage, including the power supply agreement between Supplier and Cape Light Compact.

7. The limit of commercial general liability insurance shall be at least $5 million each occurrence. Separate aggregate limits of $5 million may be applicable to products and completed operations liability coverage and failure to supply liability coverage.

8. The Supplier shall maintain umbrella or excess liability insurance subject to a limit of at least $5 million in addition to commercial general liability insurance policy limits.

9. Such liability insurance shall include Cape Light Compact and member municipalities as additional insureds, but only for obligations arising out of this agreement.

10. The policies shall be endorsed to require that such additional insureds receive at least 30-days notice of cancellation or non-renewal.

11. Such insurance shall contain a standard separation of insureds clause, whereby the actions of one insured will not negate coverage for another insured.

12. The Supplier shall provide Cape Light Compact with a certificate of insurance to evidence compliance with the requirements. Renewal certificates shall be provided automatically within 30 days of policy renewal throughout the term of the contract and two (2) years following the contract term.

Community Choice Aggregation
Draft Implementation Plan

Appendix D:
Electric Service Providers Registered In California with Service Agreements on File with Pacific Gas & Electric Company

Prepared
By
The San Francisco Public Utilities Commission

ESPs CURRENTLY CAPABLE OF SERVING SAN FRANCISCO

San Francisco may contract with an Electric Service Provider (ESP) to perform some portion of the CCA's electrical supply responsibilities. Section 4 of the CCA Ordinance describes the CCA's solicitation process. This section directs SFE and the SF PUC to present to the Board of Supervisors a draft Request for Proposals (RFP) for a CCA program for San Francisco after the Board has adopted an Implementation Plan. The RFP is assumed to be used by ESPs for submitting proposals for implementing the adopted Implementation Plan. In addition, as a statutory requirement of AB 117, CCA Implementation Plans submitted to the CPUC for certification are required to include a description of any third parties that will be supplying electricity to the CCA, including but not limited to the financial, technical, and operational capabilities.[1] It is possible that a CCA as a governmental entity could develop the resources required to independently supply electricity to its residents and businesses without an ESP or other wholesale provider (such as a municipal utility). The statute only requires that if a third party is going to be providing supply services to the CCA that the entity or entities be described in the Implementation Plan.

If the CCA decides to partner with a third party to provide electricity supply services to its customers, it may choose to contract with a CPUC registered ESP. As stated above, the CPUC has registration requirements, which include the filing of financial, technical, and operational information.[2] The general ESP registration requirements are listed below. These requirements may be important to CCSF if the City wants its CCA to serve its own customers at some point. It is possible the CPUC may require a CCA to register by providing the same information and bonding requirements as an ESP

1. Execute a UDC-ESP Service Agreement with each Utility Distribution Company in which service territory you plan to offer service and submit copies of each executed Service Agreement with your application.
2. Complete and return ESP Registration Application Form as modified in CPUC Decision (D.03-12-015).
3. Provide Fingerprints as prescribed for required personnel.
4. Post a minimum security deposit of $25,000 in the form of either a cashier's check or a financial guarantee Bond with the CPUC at the time of registration.
5. Prior to signing up and initiating a Direct Access Service Request on behalf of any customer, execute an agreement with a scheduling coordinator (SC) authorized by the Independent System Operator (ISO). Submit copies of all SC Agreements (waived For ESPs authorized as SCs).
6. For ESPs offering electric service to residential or small commercial customers, submit a copy of your Section 394.5 Notice to the Energy Division

[1] Public Utilities Code Section 366.2(c)(3)(G)

[2] If the links above do not work, ESP registration requirements and forms can be found on the CPUC's website via the following link: http://www.cpuc.ca.gov/static/industry/electric/electric+markets/electric+service+providers/registration+and+requirements/index.htm

of the CPUC on or before the date you sign up your first such customer or when the first standard service plan filing is due, whichever is earliest.

Since it is impossible to provide the technical, financial or other capabilities of a third party supplier until such a supplier is selected, the SF PUC has provided a list of ESPs currently registered with the CPUC and capable of providing supply services to a CCA in PG&E's service territory.[3]

ESP's can serve customers in the service territory of the Utility Distribution Company (UDC) checked	Bonded?	UDC Agreement with PG&E?
New West Energy PO BOX 61868, MAILING STATION ISB 665 PHOENIX, AZ 85082-1868 **Phone: (888) 639-9674** **Fax: (602) 236-5443** **E-mail: tmrabico@sprnet.com** Offering new service to: None	**Yes**	**Yes**
electricAmerica 600 ANTON BOULEVARD SUITE 2000 **COSTA MESA, CA 92626** **Phone: (714) 259-2508** **Fax: (714) 259-2516** **E-mail: igoodman@electric.com**	**Yes**	**Yes**
Offering new service to: All Customers		
American Utility Network (A.U.N.) 10705 DEER CANYON DRIVE ALTA LOMA, CA 91737	**Yes**	**Yes**

ESP's can serve customers in the service territory of the Utility Distribution Company (UDC) checked	Bonded?	UDC Agreement with PG&E?
Coral Power, L.L.C. 4445 EASTGATE MALL, SUITE 100 SAN DIEGO, CA 92121 **Phone: (858) 320-1500** **Fax: (858) 320-1550** **E-mail: hharris@coral-energy.com** Offering new service to: Large Customers	**Yes**	**Yes**
APS Energy Services Company, Inc. 400 E. VAN BUREN STREET, SUITE 750 PHOENIX, AZ 85004 **Phone: (602) 744-5364** **Fax: (602) 744-5236** **E-mail: sjenine.schenk@apses.com** Offering new service to: Large Customers	**Yes**	**Yes**
Calpine PowerAmerica-CA, LLC 4160 DUBLIN BLVD. DUBLIN, CA 94568 **Phone: (925) 479-6600**	**Yes**	**Yes**

[3] This information is current as of 03-18-05, updates can be found at: http://www.cpuc.ca.gov/published/ESP_Lists/esp_udc.htm

Phone: (909) 484-1858 Fax: E-mail: Offering new service to: All Customers		
Energy America, LLC 263 TRESSER BLVD., ONE STAMFORD PLAZA 8TH FLOOR STAMFORD, CT 06901 Phone: (416) 590-3290 Fax: (416) 590-3632 E-mail: adrian.pye@na.centrica.com Offering new service to: Residential/Small Commercial	Yes	Yes
3 Phases Electrical Consulting 2100 SEPULVEDA BLVD, SUITE 15 MANHATTAN BEACH, CA 90266 Phone: (310) 798-5275 Fax: (310) 545-4218 E-mail: mmazur@3phases.com Offering new service to: Residential/Small Commercial	Yes	Yes
Strategic Energy, L.L.C. 7220 AVENIDA ENCINAS, SUITE 120 CARLSBAD, CA 92009 Phone: (888) 925-9115 Fax: (412) 258-4866 E-mail: customerrelations@sel.com Offering new service to: All Customers	Yes	Yes
Fax: (925) 479-7304 E-mail: curth@calpine.com Offering new service to: Large Customers		
Sempra Energy Solutions 101 ASH STREET, HQ09 SAN DIEGO, CA 92101-3017 Phone: (877) 273-6772 Fax: (619) 696-3103 E-mail: email@semprasolutions.com Offering new service to: Large Customers	Yes	Yes
Pilot Power Group, Inc. 9320 CHESAPEAKE DRIVE, SUITE 112 SAN DIEGO, CA 92123 Phone: (858) 627-9577 Fax: (858) 627-9581 E-mail: tdarton@pilotpowergroup.com Offering new service to: Large Customers	Yes	Yes
BP Energy Company 501 WESTLAKE PARK BLVD. HOUSTON, TX 77079 Phone: (281) 366-4627 Fax: (281) 366-2200 E-mail: prescorw@bp.com Offering new service to: Large Customers	Yes	Yes
Constellation NewEnergy, Inc.	Yes	Yes

AOL Utility Corp. 12752 BARRETT LANE SANTA ANA, CA 92705 **Phone: (714) 669-2743** **Fax: (775) 406-3253** **E-mail: lalehs101@hotmail.com** Offering new service to: All Customers	**Yes**	**Yes**

350 SOUTH GRAND AVENUE, SUITE 2950 LOS ANGELES, CA 90071 **Phone: (888) 526-0486** **Fax: (213) 576-6070** **E-mail: carol.schoenbachler@constellation.com** Offering new service to: Large Customers		